



National Energy Board

REASONS FOR DECISION

In the matter of applications under Part VI
of the National Energy Board Act

of

ALBERTA & SOUTHERN GAS CO. LTD.
CANADIAN-MONTANA PIPE LINE COMPANY
COLUMBIA GAS DEVELOPMENT OF CANADA LTD.
CONSOLIDATED NATURAL GAS LIMITED
NIAGARA GAS TRANSMISSION LIMITED
PAN-ALBERTA GAS LTD.
PROGAS LIMITED
SULPETRO LIMITED
TRANSCANADA PIPELINES LIMITED
WESTCOAST TRANSMISSION COMPANY LIMITED

NOVEMBER 1979

NATIONAL ENERGY BOARD

REASONS FOR DECISION

In the Matter of the Applications Under Part VI
of the National Energy Board Act

of

Alberta and Southern Gas Co. Ltd.
Canadian-Montana Pipe Line Company
Columbia Gas Development of Canada Ltd.
Consolidated Natural Gas Ltd.
Niagara Gas Transmission Limited
Pan-Alberta Gas Ltd.
ProGas Limited
Sulpetro Limited
TransCanada PipeLines Limited
Westcoast Transmission Company Limited

November 1979

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RECITAL AND APPEARANCES

IN THE MATTER OF the National Energy Board Act
and the Regulations made thereunder;

AND IN THE MATTER OF applications made by Alberta and
Southern Gas Co. Ltd., Canadian-Montana Pipe Line
Company, Columbia Gas Development of Canada Ltd.,
ICG Transmission Limited, Niagara Gas Transmission
Limited, ProGas Limited, Sulpetro Limited, and Westcoast
Transmission Company Limited for licences under Part VI
of the National Energy Board Act for the export of
natural gas to the United States of America;

AND IN THE MATTER OF a joint application made by
Pan-Alberta Gas Ltd., TransCanada PipeLines Limited, and
Consolidated Natural Gas Limited, for licences under Part
VI of the National Energy Board Act for the export of
natural gas to the United States of America;

AND IN THE MATTER OF applications by Q & M Pipe Lines
Ltd., TransCanada PipeLines Limited, and ICG Transmission
Limited for certificates of public convenience and
necessity under Part III of the National Energy Board
Act;

Licence Phase (Export of Natural Gas)

Heard in Ottawa, Ontario on 10, 11, 12, 16, and 17 July, and 8 and
9 August 1979, and in Calgary Alberta on 23, 24, 25, 26, 27, 30 and
31 July and 1, 2 and 3 August 1979.

BEFORE:

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Presiding Member

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Member

J.R. Jenkins

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C.K. Yates	Independent Petroleum Association
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D.G. Hart	ProGas Limited
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W. Muscoby	Texaco Canada Inc.
Joe Weiler	Texas Eastern Transmission Corporation

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A. Butler	Union Gas Limited
L.D. Rae	Union Oil Company of Canada Limited
W.O. Crain, Jr.	United Gas Pipe Line Company
W.S. Strecker	Wainoco Oil and Gas Limited
Thomas F. Brosman	Washington Natural Gas Company
J.W. Lutes	Westcoast Transmission Company Limited
K.J. MacDonald	National Energy Board
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TABLE OF CONTENTS

	Page
Recital and Appearances	(i)
Table of Contents	(ix)
Abbreviations of Names	(xii)
List of Tables	(xvi)
List of Figures	(xviii)
List of Appendices	(xx)
Abbreviations of Terms	(xxi)
Reference Reports	(xxii)
Definitions	(xxiii)
Notes on the Use of Units in This Report	(xxix)
Metric Conversion Table	(xxx)
1. INTRODUCTION	1-1
2. THE APPLICATIONS	2-1
2.0 Introduction	2-1
2.1 Alberta and Southern	2-1
2.2 Canadian-Montana	2-3
2.3 Columbia	2-4
2.4 Niagara	2-5
2.5 ProGas	2-5
2.6 Sulpetro	2-6
2.7 Westcoast	2-7
2.8 Joint Applicants	2-7
2.8.1 Pan-Alberta	2-8
2.8.2 TransCanada	2-9
2.8.3 Consolidated	2-10
3. NATURAL GAS SUPPLY	3-1
3.1 Reserves	3-1
3.1.1 Introduction	3-1
3.1.2 Evidence of Applicants	3-1
3.1.3 Evidence of Intervenor	3-5
3.1.4 Views of the Board	3-10
3.1.4.1 Established Reserves	3-10
3.1.4.2 Reserves Additions and Ultimate Potential	3-12
3.2 Deliverability	3-15
3.2.1 Introduction	3-15
3.2.2 Evidence of Applicants	3-15
3.2.3 Evidence of Intervenor	3-16
3.2.4 Views of the Board	3-18

	Page
4. NATURAL GAS REQUIREMENTS	4-1
4.1 Introduction	4-1
4.2 Evidence	4-1
4.2.1 Demographic and Economic Growth	4-1
4.2.2 Energy Prices and Interfuel competition	4-2
4.2.3 Forecast of Total Energy Demand	4-4
4.2.4 Forecast of Natural Gas Demand (Existing Markets)	4-5
4.2.5 Expanded Markets for Natural Gas	4-8
4.3 Conclusions	4-9
5. EVIDENCE IN REGARD TO THE APPLICATIONS	5-1
5.1 Alberta and Southern	5-1
5.2 Canadian-Montana	5-7
5.3 Columbia	5-14
5.4 Niagara	5-21
5.5 ProGas	5-23
5.6 Sulpetro	5-33
5.7 Westcoast	5-40
5.8 The Joint Application	5-50
5.8.1 Pan-Alberta	5-51
5.8.2 TransCanada	5-64
5.8.3 Consolidated	5-74
6. INTERVENTIONS	6-1
6.1 Introduction	6-1
6.2 Associations	6-1
6.3 Producers	6-4
6.4 United States Customers	6-7
6.5 Other Companies	6-9
6.6 Public Interest Groups and Others	6-12
6.7 Provincial Governments	6-12
7. REASONS FOR DECISION	7-1
7.1 Introduction	7-1
7.2 General Issues	7-1
7.2.1 Exports and the Public Interest	7-1
7.2.2 Economic Impact	7-5
7.2.3 Applicants' Supply	7-6
7.2.4 The United States Regulatory Situation	7-6
7.2.5 The Prebuilt Facilities of Foothills	7-8
7.2.6 The Export Price	7-11
7.2.7 Term of Licences	7-12
7.2.8 Pipeline Facilities	7-14

	Page
8. SURPLUS	8-1
8.1 Introduction	8-1
8.2 Surplus Determination Tests	8-1
8.3 Surplus Calculation Procedures	8-2
8.4 Input Into Surplus Determination	8-3
8.5 The Board's Findings on Surplus	8-4
9. DECISION	9-1
9.1 General Comments	9-1
9.2 Alberta and Southern	9-3
9.3 Canadian-Montana	9-7
9.4 Columbia Gas	9-11
9.5 Niagara	9-13
9.6 ProGas	9-14
9.7 Sulpetro	9-16
9.8 Westcoast	9-17
9.9 The Joint Applicants	9-21
9.9.1 Pan-Alberta	9-21
9.9.2 TransCanada	9-24
9.9.3 Consolidated	9-26
9.10 Summary	9-28

APPENDICES

ABBREVIATIONS OF NAMES

"British Columbia"	- Attorney General of the Province of British Columbia
"AERCB"	- Alberta Energy Resources Conservation Board
"Saskatchewan"	- Saskatchewan Department of Mineral Resources
"Manitoba"	- Attorney General of the Province of Manitoba
"Ontario"	- Minister of Energy of the Province of Ontario
"Québec"	- Procureur Général du Québec
"Nova Scotia"	- Nova Scotia Energy Council
"Alberta and Southern" or "A & S"	- Alberta and Southern Gas Co. Ltd.
"AEC"	- Alberta Energy Company
"ANB"	- ANB Gas Company
"AGTL"	- Alberta Gas Trunk Line Company Limited
"Amoco"	- Amoco Canada Petroleum Company Ltd.
"ANGTS"	- Alaskan Natural Gas Transportation System
"B.C. Hydro"	- British Columbia Hydro and Power Authority
"BCPC"	- British Columbia Petroleum Corporation
"CARC"	- Canadian Arctic Resources Committee
"CGA"	- Canadian Gas Association
"Canadian Hunter"	- Canadian Hunter Exploration Ltd.
"Canadian-Montana"	- Canadian-Montana Pipe Line Company
"Canadian-Montana Gas"	- Canadian-Montana Gas Company, Ltd.
"CPA"	- Canadian Petroleum Association
"Chieftain"	- Chieftain Development Co. Ltd. and Chieftain International, Inc.

"Columbia" or "Columbia Gas"	- Columbia Gas Development of Canada Ltd.
"Columbia Systems"	- Columbia Gas System, Inc.
"Columbia Transmission"	- Columbia Gas Transmission Corporation
"Consolidated"	- Consolidated Natural Gas Limited
"Consumers'"	- The Consumers' Gas Company
"Dome"	- Dome Petroleum Limited
"Dow"	- Dow Chemical of Canada, Limited
"El Paso"	- El Paso Natural Gas Company
"ERA"	- Economic Regulatory Agency
"FERC"	- Federal Energy Regulatory Commission
"Foothills"	- Foothills Pipe Lines (Yukon) Ltd.
"Gaz Métropolitain"	- Gaz Métropolitain, inc.
"GSC"	- Geological Survey of Canada
"Great Lakes"	- Great Lakes Gas Transmission Company
"Greater Winnipeg"	- Greater Winnipeg Gas Company
"Gulf"	- Gulf Canada Limited and Gulf Canada Resources Incorporated
"HBOG"	- Hudson's Bay Oil and Gas Company Limited
"Imperial"	- Imperial Oil Limited
"IPAC"	- Independent Petroleum Association of Canada
"IGUA"	- Industrial Gas Users Association
"Inland"	- Inland Natural Gas Co. Ltd.
"ICG"	- ICG Transmission Limited
"Interprovincial Steel" or "IPSCO"	- Interprovincial Steel and Pipe Corporation Ltd.

"Kingston PUC"	- Public Utilities Commission of the City of Kingston
"Michigan Wisconsin"	- Michigan Wisconsin Pipe Line Company
"Midwestern"	- Midwestern Gas Transmission Company
"Minnesota PSC"	- Minnesota Public Service Commission
"Montana Power"	- The Montana Power Company
"Natural Gas Pipe"	- Natural Gas Pipeline Company of America
"NDP"	- New Democratic Party
"Niagara"	- Niagara Gas Transmission Limited
"Norcen"	- Norcen Energy Resources Limited
"North Dakota PSC"	- North Dakota Public Service Commission
"NC Gas"	- Northern and Central Gas Corporation Limited
"Northern Border"	- Northern Border Pipeline Company
"Northern Natural"	- Northern Natural Gas Company
"Northwest Alaskan"	- Northwest Alaskan Pipeline Company
"Northwest"	- Northwest Pipeline Corporation
"PG & E"	- Pacific Gas and Electric Company
"PGT"	- Pacific Gas Transmission Company
"Pacific Interstate"	- Pacific Interstate Transmission Company
"Pacific Lighting"	- Pacific Lighting Exploration Company
"Pan-Alberta"	- Pan-Alberta Gas Ltd.
"Panhandle"	- Panhandle Eastern Pipe Line Company
"Polar Gas"	- Polar Gas Limited
"ProGas"	- ProGas Limited
"Q & M"	- Q & M Pipe Lines Ltd.
"Quintana"	- Quintana Exploration Canada Ltd.
"Saskatchewan Power"	- Saskatchewan Power Corporation

"Shell"	- Shell Canada Resources Limited
"St. Lawrence"	- St. Lawrence Gas Company, Inc.
"SoCal"	- The Southern California Gas Company
"Sulpetro"	- Sulpetro Limited
"Tennessee"	- Tennessee Gas Pipeline Company
"Texas Eastern"	- Texas Eastern Transmission Corporation
"TransCanada" or "TCPL"	- TransCanada PipeLines Limited
"Transco"	- Transcontinental Gas Pipe Line Corporation
"United"	- United Gas Pipeline Company
"Union Gas"	- Union Gas Limited
"Washington Natural"	- Washington Natural Gas Company
"Westcoast Petroleum"	- Westcoast Petroleum Ltd.
"Westcoast"	- Westcoast Transmission Company Limited
"Western Decalta"	- Western Decalta Petroleum (1977) Limited
"Wintershall"	- Wintershall Oil of Canada Ltd.
"Zephyr"	- Zephyr Resources Ltd.

LIST OF TABLES

Table	Title	Page
<u>Chapter 3</u>		
3.1.1.A	Remaining Reserves of Marketable Natural Gas Conventional Producing Areas of Western Canada	3-2
3.1.1.B	Marketable Natural Gas Reserves Additions Forecasts - Conventional Producing Areas of Western Canada 1979-2000	3-3
3.1.1.C	Ultimate Potential Estimates of Marketable Natural Gas - Conventional Producing Areas of Western Canada	3-4
3.1.4.1	NEB Estimates of Remaining Established Reserves of Marketable Natural Gas - Conventional Producing Areas	3-11
3.1.4.2	Forecast of Marketable Natural Gas Reserves Additions, 1979-2000 - NEB Estimate	3-14
3.2.4.1	NEB Forecast of Total Conventional Supply Capability from Controlled Reserves	3-19
3.2.4.2	Connection Rates for Uncommitted Gas	3-21
3.2.4.3	Connection Rates for Reserves Additions.	3-22
3.2.4.4	Total Conventional Supply Capability - NEB Forecast	3-23
<u>Chapter 4</u>		
4.3.A	Total Canadian Demand for Natural Gas - Comparison of NEB Forecasts	4-11
4.3.B	Total Net Sales of Natural Gas Including Expanded Markets for Eastern Canada - NEB 1979 Gas Report Forecast	4-12
<u>Chapter 5</u>		
5.1.1	Alberta and Southern - Supply/Demand	5-4
5.2.1	Canadian-Montana - Aden Area - Supply/Demand	5-10
5.3.1	Columbia - Kotanelee Field - Supply/Demand	5-16
5.5.1	ProGas - Supply/Demand	5-24

LIST OF TABLES

Table	Title	Page
<u>Chapter 5 (cont.)</u>		
5.6.1	Sulpetro - Supply/Demand	5-36
5.7.1A	Westcoast - GL-4 - Supply/Demand	5-43
5.7.1B	Westcoast - GL-41 - Supply/Demand	5-45
5.8.1.1	Pan-Alberta - Supply/Demand	5-55
5.8.1.3.1	Pan-Alberta - Estimates of the Present Value of Net Benefits Associated with the Pan-Alberta Project	5-62
5.8.2.1	TransCanada - Supply/Demand	5-66
5.8.2.3	TCPL and Consolidated - Estimates of the Present Value (Mid-1978) of Net Benefits Associated with the TCPL and Consolidated Proposals	5-67
<u>Chapter 7</u>		
7.1	Summary of Export Applications	7-2
7.2.8.1	TransCanada Western Section - Throughput Requirements and Required Capacity Additions - NEB Estimates	7-19
7.2.8.2	TransCanada Central Section - Throughput Requirements and Required Capacity Additions - NEB Estimates	7-20
<u>Chapter 8</u>		
8.2.2	Current Deliverability Surplus	8-6
8.2.3	Current Reserves Test	8-8
8.2.4	Future Deliverability Surplus	8-10
<u>Chapter 9</u>		
9.1	Annual Natural Gas Exports Arising From Decision	9-4

LIST OF FIGURES

Figures	Title	Page
<u>Chapter 2</u>		
2.0	Pipeline Systems and Export Points	2-2
<u>Chapter 3</u>		
3.1.4.2 A	Forecast of Marketable Natural Gas Reserves Additions - Alberta	3-15
3.1.4.2 B	Forecast of Marketable Natural Gas Reserves Additions - British Columbia	3-16
3.1.4.2 C	Forecast of Marketable Natural Gas Reserves Additions - Conventional Producing Areas of Western Canada	3-17
3.2.4.4	Supply Capability from Conventional Producing Areas - NEB Forecast	3-27
<u>Chapter 5</u>		
5.1.1	Alberta and Southern - Annual Requirements vs. Supply	5-5
5.2.1	Canadian-Montana - Annual Requirements vs. Supply	5-11
5.3.1	Columbia - Annual Requirements vs. Supply	5-17
5.5.1	ProGas - Annual Requirements vs. Supply	5-25
5.6.1	Sulpetro - Annual Requirements vs. Supply	5-37
5.7.1 A	Westcoast Licence GL-4 - Annual Requirements vs. Supply	5-44
5.7.1 B	Westcoast Licence GL-41 - Annual Requirements vs. Supply	5-46
5.8.1.1	Pan-Alberta - Annual Requirements vs. Supply	5-56
5.8.2.1	TransCanada - Annual Requirements vs. Supply	5-67

LIST OF FIGURES

Figures	Title	Page
<u>Chapter 7</u>		
7.2.8.1 and 7.2.8.2	TransCanada PipeLines - Summary of Throughput Requirements	7-21
<u>Chapter 8</u>		
8.2.2	Current Deliverability Test - Canadian Requirements plus Existing and Applied-for Exports	8-7
8.2.4	Future Deliverability Test - Canadian Requirements plus Existing and Applied-for Exports	8-11
<u>Appendix C</u>		
C-1	Primary Energy Demand - Canada - NEB Forecast of Fuel Shares	15 of 31
C-2	Primary Energy Demand - Canada - Range of NEB Scenarios	18 of 31
C-3	Net Sales of Natural Gas - Canada (Existing Markets) - Range of NEB Scenarios	20 of 31

LIST OF APPENDICES

Appendix	Title
<u>APPENDIX A</u>	Board Order GH-4-79
<u>APPENDIX B</u>	List of Intervenors to Licence Phase
<u>APPENDIX C</u>	NEB Forecast of Total Energy Demand and Natural Gas Requirements
<u>APPENDIX D</u>	TransCanada Pipeline System Capability - Existing and Forecast
<u>APPENDIX E</u>	Treatment of Exports
<u>APPENDIX F</u>	Cost - Benefit Analysis of Board Decision
<u>APPENDIX G</u>	Verification of the Current Deliverability Test
<u>APPENDIX H</u>	Form of the Proposed Licences and Amending Orders

ABBREVIATIONS OF TERMS

"ACQ"	- Annual Contract Quantity
"ANGTS"	- Alaska Natural Gas Transportation System
"Bcf"	- Billion Cubic Feet
"B.E.R."	- Beyond Economic Reach
"cf/d"	- Cubic Feet per day
"CPI"	- Consumer Price Index
"EJ"	- Exajoules (10^{18} joules)
"GJ"	- Gigajoules (10^9 joules)
"GNE"	- Gross National Expenditure
"GNP"	- Gross National Product
"Mcf"	- Thousand Cubic Feet
"MJ"	- Megajoules (10^6 joules)
"MMcf"	- Million Cubic Feet
"m ³ /d"	- Cubic metres per day
"10 ³ m ³ "	- Thousand cubic metres
"10 ⁶ m ³ "	- Million cubic metres
"10 ⁹ m ³ "	- Billion cubic metres
"10 ¹² m ³ "	- Trillion cubic metres
"PJ"	- Petajoules (10^{15} joules)
"QUAD"	- Equal to 1 quadrillion Btu's (i.e. 10^{15} Btu)
"SNG"	- Synthetic Natural Gas
"TJ"	- Terajoules (10^{12} joules)

REFERENCE REPORTS

- | | |
|-----------------------------|--|
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| "AERCB Report 78-I" | - Energy Requirements in Alberta 1977-2006 - September 1978. |
| "AERCB Report 79-B" | - Summary Report on Alberta Gas Reserve and Removal Matters - June 1979. |
| "AERCB Report 79-D" | - Report to the Lieutenant-Governor in Council, in the Matter of Applications of ProGas Limited and TransCanada PipeLines Limited under the Gas Resources Preservation Act. - July 1979. |
| "AERCB Report 79-18" | - Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, - at 31 December 1978. |
| "1967 Westcoast Decision" | - National Energy Board Report to the Governor-in-Council in the Matter of the Application Under the National Energy Board Act of Westcoast Transmission Company Limited - March 1967 |

DEFINITIONS

Accelerated Exports	An export quantity of gas that exceeds the originally-licensed daily or annual quantity and that is authorized by an amending Order. Such an accelerated rate of export does not alter the original term quantity of the licence.
Annual Averaging	A condition appearing in certain existing natural gas export licences which allows for the export or "make-up" of some or all of the quantities not taken in earlier years.
Arctic Pilot Project	The Arctic Pilot Project is "designed to produce and liquefy 250 million cubic feet of natural gas per day in the Arctic and move it to Eastern Canadian markets in ice-breaking ships". An application dated 17 January 1979, was submitted to the Board by AGTL and Petro-Canada for a licence under Part VI of the National Energy Board Act to export, by displacement, this (regasified) liquefied natural gas.
Associated Gas*	Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir, except where the volume of oil is small and where production of such gas does not significantly affect the crude oil recovery.
Beyond Economic Reach Reserves	Those established reserves which because of size, geographic location or composition are not considered economically connectable to a pipeline at the present time.
Candide	A large computerized econometric model of the Canadian economy which has been developed by the Economic Council of Canada with the assistance of several departments of the Federal Government. The development of the model has been proceeding since 1970, and a recent version, CANDIDE 1.2M, was developed in 1976. The model being used at the Board is the 1.2M version with further modifications made by Board staff.
Conventional	With reference to natural gas reservoirs or production from them - those reservoirs from which natural gas will flow in commercial quantities without application of any technology other than that usually associated with gas well completions; the production from such reservoirs.

Conventional Areas	Those areas of Canada which have a lengthy history of hydrocarbon production.
Conventional Producing Areas	Same as Conventional Areas.
Daily Contract Quantity	The average daily rate of take specified in a contract negotiated between a gas supplier and a gas purchaser.
Deep Basin	In general terms, the western part of the Western Canada Sedimentary Basin characterized by rapid thickening of the Mesozoic sedimentary section westward. Canadian Hunter uses the term more specifically to describe an area immediately east of the foothills belt, extending for some 400 miles from approximately 52°30' north latitude in Alberta, to 57° in British Columbia. The Mesozoic section in this area is generally of low permeability and is considered by Canadian Hunter to be almost universally gas-saturated.
Deferred Reserves	Those volumes of established reserves which for a specific reason, usually because of involvement in a recycling or pressure maintenance project, are not now available for market.
Deliverability	A general term used to refer to an actual or expected rate of natural gas production.
Elmworth or Elmworth/Wapiti Area	An area of the Deep Basin of Alberta, centred some 20 miles southwest of Grande Prairie, currently undergoing active development of natural gas reserves.
Established Reserves*	Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
- Initial Established Reserves*	Established reserves prior to the deduction of any production.
- Remaining Established Reserves*	Initial established reserves less cumulative production.
Feedstock	Raw material supplied to a refinery or petrochemical plant.

Flat Life	That period of the producing life of a resource during which production is maintained at a constant rate before decline commences.
Frontier Areas	Those areas of Canada which have a potential for but no history of production. These include the Mackenzie Delta-Beaufort Sea area, the Arctic Islands and the offshore areas.
Frontier Reserves	Reserves located in the frontier areas.
Heavy Fuel Oil	In this report the term heavy fuel oil is used to include bunker fuel oils which are No. 5 and No. 6 fuel oils and also industrial fuel oil which is No. 4 fuel oil.
Hog Fuel	Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects that result from the operation of pulp mills, sawmills and plywood mills.
International Price of Crude Oil	A generalization for the "going price" of crude oil in the world markets.
Light Fuel Oil	In this report the term light fuel oil is used to include furnace fuel oil which is No. 2 fuel oil and stove oil which is No. 1 fuel oil. The major volume of light fuel oil used in Canada is furnace fuel oil.
Marketable Natural Gas*	Natural gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial, or industrial fuel. Marketable natural gas excludes field and plant fuel and losses, excepting those related to downstream reprocessing plants.
Natural Gas Liquids*	Natural gas liquids are those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers, or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes, and pentanes plus or a combination thereof.

Non-Associated Gas*	Natural gas not in contact with crude oil in the reservoir or natural gas in contact with crude oil where the volume of oil is small and where production of such gas does not significantly affect the crude oil recovery.
Permeability	Permeability is a property of a porous medium and is a measure of the capacity of the medium to transmit fluids.
Play-Horizon Method	A method of assessing ultimate potential involving evaluation of individual trends or patterns of occurrence of geologically similar exploration prospects.
Pulping Liquor(also known as waste liquor or black liquor)	A substance primarily made up of lignin, a substance found in wood, and is a by-product of the manufacture of chemical pulp. It can be burned in a boiler to produce steam or electricity.
Rate of Take	The average daily rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which that production is obtained. For example 1:7300 means one standard cubic metre per day of production for each block of 7300 cubic metres of initial established reserves.
Raw Natural Gas*	The lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which, under atmospheric conditions, are essentially a gas, but which may contain liquids.
Remaining Established Reserves	See "Established Reserves"
Reserves Additions	Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.
Reserves Appreciation	Incremental change in established reserves resulting from extensions and revisions to existing pools.
Solution Gas*	Natural gas which is in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.

Southern Territories	The region of the Yukon and Northwest Territories considered to be within the conventional producing areas and is limited to being only that immediately adjacent to the territorial provincial boundary lines.
Straddle Plant	A natural gas processing plant in which gas is further processed, subsequent to field processing, to remove liquid components. Generally, the plant is located on a main transmission system and is said to "straddle" the pipeline; also known as a reprocessing plant.
Supply Capability	The deliverability that could be achieved from a gas reservoir or group of reservoirs when restricted only by reservoir performance, well density and well capacity, field processing capacity, and contract rates.
Supply Tracking	A supply forecasting procedure utilized during a period when supply capability exceeds demand, whereby deliverability is restricted to (or "tracks") that demand until such time as supply capability falls below the demand level.
Synthetic Natural Gas	Synthetic or substitute natural gas made synthetically from petroleum liquids or coal.
Toronto Reference Price (Toronto City Gate)	The price of Alberta gas delivered at Toronto, determined as an energy equivalent value of the price of crude oil at Toronto, in accordance with Federal-Alberta gas-pricing agreements.
"25A1"	The Board's Current Reserves Test for determining surplus based on 25 times the first year's Canadian domestic requirement for natural gas.
"25A4"	The Board's previous procedure for determining surplus based on 25 times the fourth year's Canadian domestic requirement for natural gas.
Ultimate Potential*	An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of the area and anticipated technology and economic conditions. Ultimate potential

and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.

World Price

See "International Price"

* The Board has adopted the reserves terminology and definitions recommended by the Joint Task Force on Uniform Reserves Terminology, 1978. Definitions marked * are Task Force definitions of terms used in this report.

NOTE ON THE USE OF UNITS IN THIS REPORT

On 1 January 1978, the National Energy Board adopted the use of the international system of units (SI). However, the use of either Imperial or SI units for the 1978 calendar year was left optional for companies in their dealings with the Board. As a result, in a number of the applications before the Board for this Hearing, Imperial units were used, while in others, SI was used.

The Board has adopted the following procedure in the use of units:

- In matters concerning natural gas supply, demand, and surplus (in particular, Chapters 3, 4, and 8), the Board has in general utilized the SI measure of energy or heat content - the joule. The symbol for the joule is "J", and in general it is referred to in one of four common multiples:

GJ - gigajoule = 1 000 000 000 J

TJ - terajoule = 1 000 000 000 000 J

PJ - petajoule = 1 000 000 000 000 000 J

EJ - exajoule = 1 000 000 000 000 000 000 J

In addition to the use of the joule, the Board has reflected evidence submitted by parties to the Hearing in the units used for the evidence, by showing that evidence in brackets following the SI units.

- In matters concerning other evidence, and in the decision (Chapters 1, 2, 5, 7, and 9), the Board has in general used the SI measure for volume - the cubic metre. The symbol used is "m³", and in general it is used in one of three common multiples:

$$\begin{aligned}
 10^3 \text{ m}^3 &= 1\,000 \text{ cubic metres} \\
 10^6 \text{ m}^3 &= 1\,000\,000 \text{ cubic metres} \\
 10^9 \text{ m}^3 &= 1\,000\,000\,000 \text{ cubic metres}
 \end{aligned}$$

Again, the Board has reflected evidence submitted by parties to the Hearing in the units used for the evidence, by showing that evidence in brackets following the SI units.

* * * * *

METRIC CONVERSION TABLE

1 cubic foot of natural gas (@ 14.73 psia and 60°F)	=	0.028 327 84 cubic metres
1 cubic metre of natural gas	=	35.301 cubic feet
1 Btu 60/61	=	1 054.615 joules
1 Mcf (@14.73 psia)	=	28.327 84 m ³
1 MMcf (@14.73 psia)	=	28 327.84 m ³ or 28.327 84 x 10 ³ m ³
1 Bcf	=	28 327 840 m ³ or 28.327 84 x 10 ⁶ m ³
1 x 10 ³ m ³	=	35.301 Mcf
1 x 10 ⁶ m ³	=	35.301 MMcf
1 x 10 ⁹ m ³	=	35.301 Bcf

RULES OF THUMB (approximate equivalent volumes of natural gas)

1 GJ	=	0.95 Mcf
1 TJ	=	0.95 MMcf
1 PJ	=	0.95 Bcf
1 EJ	=	0.95 Tcf

CHAPTER 1
INTRODUCTION

In early 1978, the National Energy Board concluded that circumstances in the natural gas industry in Canada had become sufficiently changed from those which had prevailed during the mid-1970's to warrant a new appraisal of the supply of gas in relation to reasonably foreseeable requirements for Canadian use and for authorized exports. Among the circumstances which appeared to the Board to have altered the Canadian natural gas situation were the renewed vigour of exploration and development activities in the Western Canada Sedimentary Basin and an apparent reduction in the rate of growth in natural gas demand in Canada arising from the increased price of natural gas and the resultant induced new awareness of energy conservation by consumers.

The Board also felt that it was appropriate to re-examine its procedures for determining the surplus of gas in Canada, a review first indicated as necessary in the Board's 1975 Gas Report. Accordingly, by its Hearing Order GHR-1-78, the Board held a public inquiry commencing 11 October 1978 to receive advice from the energy sector, the provinces, and the general public on matters of gas reserves and deliverability, demand, and surplus. The Board's findings resulting from that inquiry were contained in its 1979 Gas Report.

Among the main conclusions arising from that inquiry, the Board found:

- (a) Remaining established reserves at the end of 1978 in conventional areas were estimated to be 69.7 EJ (66.1 Tcf), some 5.0 EJ (4.7 Tcf) more than estimated for year-end 1976 in the Northern Pipelines Report.
- (b) Growth in natural gas demand in Canada would be slower than that forecast in the Northern Pipelines Report.
- (c) The determination of a surplus of natural gas should be made using three tests:
 - a Current Deliverability Test;
 - a Current Reserves Test; and
 - a Future Deliverability Test.

All three tests would have to be met before the Board would deem a surplus to exist.

- (d) On the basis of these three tests, a surplus of approximately 2.1 EJ (2 Tcf) of gas existed at the end of 1978.

Two applications were received by the Board in June 1978, that of Sulpetro and a joint application by TransCanada and Consolidated, and twelve more applications were received by the Board by May 1979. The fourteen applications sought approval to export a total of 9.3 EJ (8.8 Tcf)

Two applications were withdrawn. The joint application dated 2 June 1978 of TransCanada and Consolidated was withdrawn in June 1979, being superseded by separate applications of the two companies; and, at the opening of the hearing on 10 July 1979, ICG Transmission Limited withdrew its application of 30 March 1979 for both a licence to export gas and a certificate of public convenience and necessity to construct additional facilities to accommodate that export. On 4 May 1979, a new application was filed as a Joint Application by Consolidated, Pan-Alberta and TransCanada incorporating the applications the Board had earlier received separately from the three companies.

Two other important applications had been received by the Board in 1978 which directly affected the supply and disposition of natural gas in Canada. In April 1978, TransCanada had filed an application to extend its pipeline east of Montreal, and in October 1978, Q & M filed a competing application to build a new pipeline from Montreal to Nova Scotia. Both proposals would provide for the extension of natural gas service to those areas of Quebec, New Brunswick and Nova Scotia not now served by natural gas. TransCanada subsequently withdrew its 1978 application when it filed in April 1979 a revised, enlarged pipeline proposal.

It appeared to the Board that the various applications to export natural gas and the applications to extend the gas transmission pipeline east of Montreal should be considered within the fabric of one omnibus hearing. The Board recognized that it would be desirable to

consider first the applications to extend natural gas service to the east of Montreal, but it became apparent that the complexity of the pipeline applications, together with advice received from the two applicants that they would be unable to assemble and file all of the information to complete their applications before late in the summer of 1979, would preclude commencing the hearing of the pipeline applications before the fall. As a result, consideration of the export applications would have had to have been deferred until well into 1980. On the other hand, it was the Board's view that it would be possible to proceed first with the export applications during the summer.

The Board felt that proceeding with the export applications would afford two benefits. First, to the extent that it might be in the public interest to allow at least some new gas exports to begin in time to serve the immediate heating season commencing 1 November 1979, an early decision could lead to such early new exports. Second, to the extent that planning and arranging financing of the Foothills pipeline, as part of the ANGTS, would be facilitated by a decision to prebuild southern portions of that system, and, as a decision to prebuild is intrinsically entwined with the Pan-Alberta application, an early decision by the Board with respect to the Pan-Alberta application would assist the backers of the ANGTS, including Foothills, in determining whether prebuilding should be pursued.

One other factor influenced the Board's decision on how to proceed with the various applications. While for previous natural gas export hearings the Board had first examined Canadian requirements, reserves, and surplus, the Board's 1978 Gas Inquiry leading to the 1979 Gas Report had already resulted in a finding that a surplus of gas existed, after having taken into account the estimated requirements of expansion markets in Quebec and the Maritimes. The Board concluded that it could proceed with the export applications first with the knowledge that it had already made provision for the gas requirements of the expansion market.

It was with these considerations in mind that the Board issued Order No. GH-4-79, setting down the procedures by which it would conduct the public hearing of the gas export applications and the two natural gas pipeline certificate applications. The Licence Phase of the Hearing began in Ottawa on 10 July 1979, moved to Calgary on 23 July 1979, and concluded in Ottawa on 9 August 1979. This report deals only with the Licence Phase of the Hearing. A separate report will be issued later dealing with the Certificate Phase of the Hearing.

CHAPTER 2
THE APPLICATIONS

2.0 Introduction

This chapter outlines the main elements of the applications for licences to export natural gas dealt with by the Board in the Licence Phase of the hearing. The Board had 11 applications before it following the withdrawal of the application of ICG at the opening of the hearing on 10 July 1979. Two companies, Canadian-Montana and Westcoast, had two or more applications before the Board, while three companies, Consolidated, Pan-Alberta, and TransCanada, combined their individual applications into one joint application. The Applicants in the Licence Phase were:

- Alberta and Southern
- Canadian-Montana (2 applications)
- Columbia
- Niagara
- ProGas
- Sulpetro
- Westcoast (3 applications)
- Joint Application of Pan-Alberta, TransCanada, and Consolidated

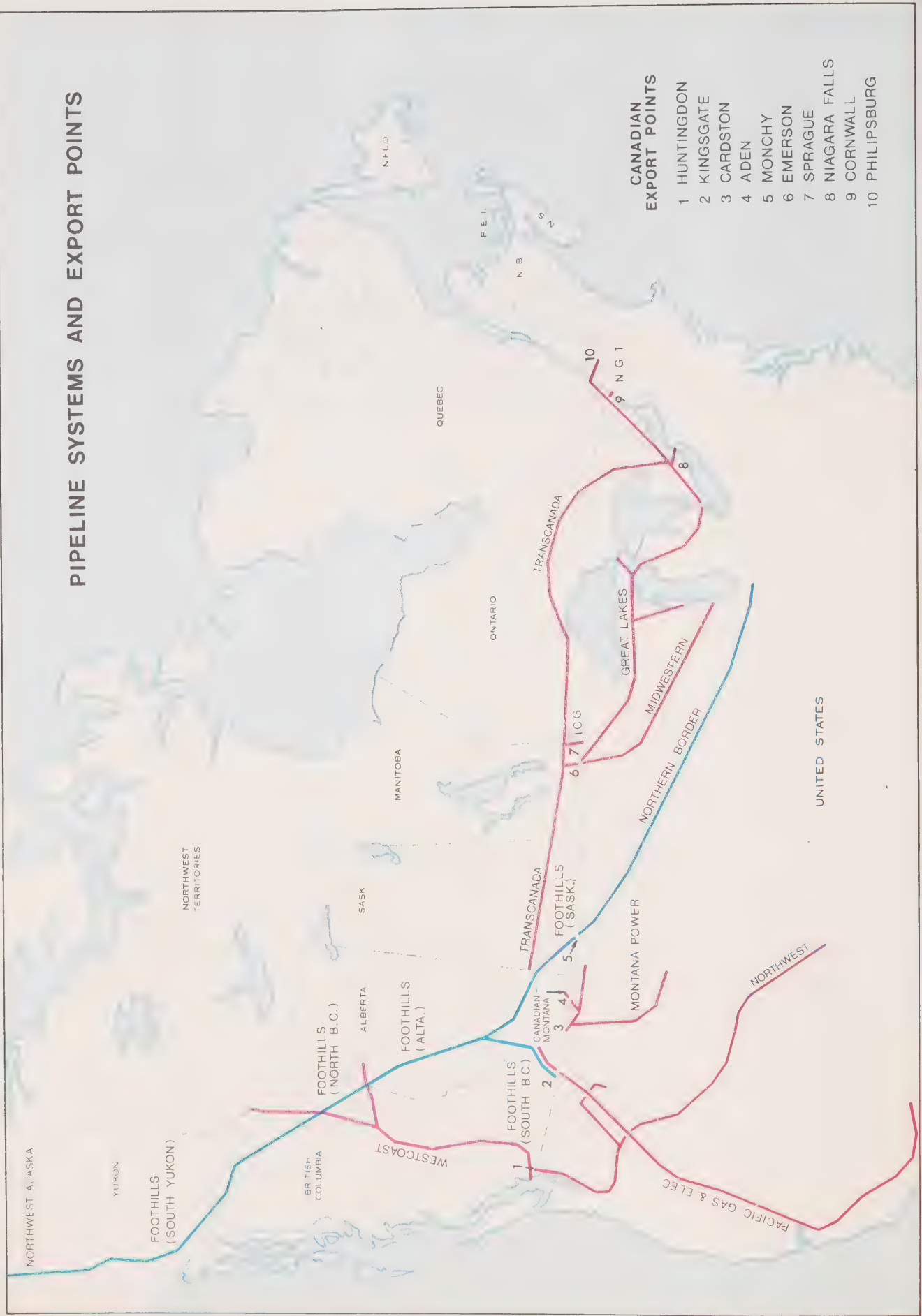
Figure 2.0 provides a map of the pipeline systems that would carry the proposed exports to the international boundary, and shows the main connecting pipelines in the United States.

2.1 Alberta and Southern

Alberta and Southern, a company incorporated under the laws of the Province of Alberta, is a wholly-owned subsidiary of PG&E and is the holder of gas export Licences GL-3, GL-16, GL-24, and GL-35. Alberta and Southern purchases gas in Alberta from various producers. The gas is transported through the facilities of AGTL to the Alberta-British Columbia boundary, and, from this point to the international boundary at Kingsgate, B.C., through the facilities of Alberta Natural, a company controlled by PGT, which is in turn controlled by PG&E. At the international boundary, the gas is sold by Alberta and Southern to PGT, which transports the gas to California for resale to PG&E.

FIGURE 2.0

PIPELINE SYSTEMS AND EXPORT POINTS



Alberta and Southern applied for an extension of gas exports near Kingsgate, British Columbia under Licences GL-35 and GL-3, for a period commencing 1 November 1985 and 1 November 1986, respectively, and ending 31 October 1989, as follows:

	<u>Additional Volumes</u>	
	<u>Licence GL-35</u>	<u>Licence GL-3</u>
	<u>10^6 m^3</u>	<u>10^6 m^3</u>
Daily Maximum	5.8	12.9
Annual Average	1 912	4 342
Total Additional	7 649	13 025

2.2 Canadian-Montana

Canadian-Montana, a company incorporated by a Special Act of the Parliament of Canada, is a wholly-owned subsidiary of Montana Power, a regulated public utility incorporated under the laws of the State of Montana.

Canadian-Montana is the holder of Licences GL-5, GL-17, GL-25 and GL-36 for the export of gas from Canada at points on the international boundary near Cardston, Alberta and Aden, Alberta.

Canadian-Montana filed two applications for natural gas exports. The first application, dated 21 March 1979, sought four separate approvals by the Board:

- (i) a new eight-year licence commencing 1 January 1980 to export at Aden a daily volume of $1\,416.4 \times 10^3 \text{ m}^3$, an annual maximum of $283 \times 10^6 \text{ m}^3$, and a term volume of $2\,266 \times 10^6 \text{ m}^3$.
- (ii) amendments to its four existing licences to increase the total, or term, volume authorized for export under each licence, as follows:

<u>Licence No.</u>	<u>Proposed Additional Term Volume</u>
	<u>10^6 m^3</u>
GL-5	466
GL-17	265
GL-25	1 522
GL-36	23
Total	2 276

- (iii) amendments to its four existing licences, which would have the effect of reinstating the various conditions which applied to the daily and annual volumes of the licences prior to 1 June 1973. In brief, the requested amendments would reduce the maximum annual exportable volume under the four licences from $968.8 \times 10^6 \text{ m}^3$ to $827.2 \times 10^6 \text{ m}^3$.
- (iv) amendments to its four existing licences, which would delete Aden as an authorized export point for exports made under those licences.

Canadian-Montana sought, through items (ii), (iii) and (iv), to reinstate such terms and conditions in its four existing licences that would make them the same as if no accelerated exports had been authorized under the licences since the expiry of Licence GL-8 in 1973. Items (i) and (ii) would provide for total new exports of $4\,542 \times 10^6 \text{ m}^3$.

In its second application, Canadian-Montana applied on 21 April 1979 for extensions to Licences GL-5 and GL-36, for periods of three and four years respectively, both ending 31 October 1989, and to increase the authorized term quantities in the two licences by a total of $1\,344 \times 10^6 \text{ m}^3$.

In summary, the total new export volumes sought by the two applications are:

<u>Designation</u>	<u>Additional Term Volume</u>
	<u>10^6 m^3</u>
New Aden Licence	2 266
Existing Licences	<u>3 621</u>
	5 887

2.3 Columbia Gas

Columbia Gas, a company incorporated under the laws of Canada, is a wholly-owned subsidiary of Columbia Systems of Wilmington, Delaware.

Columbia Gas applied for a licence for the export of $5\,779 \times 10^6 \text{ m}^3$ (204 Bcf) of gas from the Kotaneelee Field in the Yukon Territory over a 15-year term commencing 1 January 1980 with a daily volume of $1\,161.4 \times 10^3 \text{ m}^3$ (41 MMcf) and an annual volume of $385.3 \times 10^6 \text{ m}^3$ (13.6 Bcf).

Under the proposal, gas produced in the Kotaneelee field would be transported through the facilities of Westcoast for export at a point on the international boundary near Huntingdon, B.C., at the interconnection of Westcoast and Northwest facilities. The gas, upon entering the United States, would be delivered to the eastern market area served by Columbia Transmission through exchange arrangements involving Northwest and El Paso.

2.4 Niagara

Niagara, a company incorporated under the laws of the Province of Ontario, is the holder of Licence GL-6, under which it is authorized to export gas at Cornwall, Ontario to St. Lawrence, a gas distribution utility in northern New York State. Both Niagara and St. Lawrence are wholly-owned subsidiaries of Consumers'. Niagara owns and operates a 14 km transmission pipeline between the take-off point on the TransCanada system and the international boundary.

Niagara applied for a new licence for the export of gas to St. Lawrence for a term commencing 1 November 1979 and ending 31 October 1995. During the period 1 November 1979 to 31 October 1985, Niagara would be authorized to export a daily volume of $350 \times 10^3 \text{ m}^3$ and an annual volume of $89.1 \times 10^6 \text{ m}^3$. For the balance of the term beginning 1 November 1985, Niagara would be authorized to export a daily volume of $1\,200 \times 10^3 \text{ m}^3$ and an annual volume of $273.5 \times 10^6 \text{ m}^3$. The total term volume applied for was $3\,300 \times 10^6 \text{ m}^3$.

2.5 ProGas

ProGas is incorporated under the provisions of the Canada Business Corporations Act and is currently sponsored by 13 natural gas producing companies.

ProGas applied for a licence to export gas near Emerson, Manitoba during the period 1 November 1980 to 31 October 1989, at the following rates:

- a) a daily volume of $9\,489.8 \times 10^3 \text{ m}^3$ during the first five years of the licence, and, during each of the next four years, a daily volume equal to 80 percent, 60 percent, 40 percent, and 20 percent respectively of $9\,489.8 \times 10^3 \text{ m}^3$.

- b) an annual volume of $3\,116 \times 10^6 \text{ m}^3$ during the first five years of the licence, and, during each of the next four years, an annual volume equal to 80 percent, 60 percent, 40 percent, and 20 percent respectively of $3\,116 \times 10^6 \text{ m}^3$.
- c) during the nine-year term a total of $21\,727 \times 10^6 \text{ m}^3$.

ProGas also applied for a provisional licence that would allow it, after 31 October 1985, to export to its U.S. purchasers gas not taken by TransCanada from time to time under the gas sales agreement entered into between ProGas and TransCanada.

The gas proposed to be exported by ProGas would originate in the Province of Alberta and would be transported to Emerson by TransCanada. From Emerson the gas would be delivered by exchange arrangements to ProGas's four U.S. purchasers, Michigan Wisconsin, Natural Gas Pipe, Tennessee, and Texas Eastern.

2.6 Sulpetro

Sulpetro, a company incorporated under the laws of the Province of Alberta, participates in the exploration for and the development of petroleum and natural gas and is a working-interest owner in five gas fields in Alberta. Sulpetro proposes to export gas produced from these fields.

Sulpetro applied for a licence to export gas near Niagara Falls, Ontario over a three-year term commencing on 1 November 1979. Sulpetro proposes to export a daily volume of $2\,124.6 \times 10^3 \text{ m}^3$, an annual volume of $623.2 \times 10^6 \text{ m}^3$, and $1\,870 \times 10^6 \text{ m}^3$ during the term.

The gas to be exported would be transported by TransCanada for Sulpetro to Niagara Falls, from where it would be delivered through an exchange arrangement to Sulpetro's U.S. customer, Transco.

2.7 Westcoast

Westcoast, a company incorporated by Special Act of the Parliament of Canada, is engaged in purchasing natural gas in the Provinces of Alberta and British Columbia and in the Yukon and Northwest Territories. It is also engaged in the gathering, processing, and transmitting of gas in Canada and in selling gas to markets in Canada and in the United States. Westcoast is authorized to export gas to Northwest under Licence GL-4 at Kingsgate, B.C. and under Licence GL-41 at Kingsgate and Huntingdon, B.C.

Westcoast applied for an extension to Licence GL-4, to provide for continued exports to 31 October 1989. The proposed licence extension would allow the export of a daily volume of $4\,305.8 \times 10^3 \text{ m}^3$, an average annual volume of $1\,444.7 \times 10^6 \text{ m}^3$, and a total volume of $5\,694 \times 10^6 \text{ m}^3$ during the term of the extension, thereby increasing total exports during the term of Licence GL-4 from $28\,894 \times 10^6 \text{ m}^3$ to $34\,588 \times 10^6 \text{ m}^3$.

Westcoast also applied for an extension of Licence GL-41 from 31 October 1989 to 31 October 1995. This proposed extension would allow the export of a daily volume of $22\,922.9 \times 10^3 \text{ m}^3$, an average annual volume of $7\,970.3 \times 10^6 \text{ m}^3$, and a total volume of $18\,383 \times 10^6 \text{ m}^3$ during the term of the extension, to increase total exports made under Licence GL-41 from $142\,853 \times 10^6 \text{ m}^3$ to $161\,236 \times 10^6 \text{ m}^3$.

Westcoast also applied for an increase in the daily and annual export volumes authorized under Licence GL-41 during the period 1 November 1980 to 31 October 1989. The proposed amendment would increase the daily volume by $1\,699.7 \times 10^3 \text{ m}^3$ to $24\,622.6 \times 10^3 \text{ m}^3$ and the average annual volume by $620.4 \times 10^6 \text{ m}^3$ to $8\,590.7 \times 10^6 \text{ m}^3$ during that period, but this would not result in any change in the term volume.

2.8 Joint Application

Pan-Alberta, TransCanada, and Consolidated originally filed separate licence applications, dated 18 April 1979, 25 January 1979, and 28 March 1979 respectively. A revised filing dated 4 May 1979 combined the three applications, but information contained in the original submissions was stated to be applicable to and part of the Joint Application.

The Joint Application, as amended on 22 July 1979, is for four licences, to be issued to the individual companies, for the export of a

firm volume of $165\,686 \times 10^6 \text{ m}^3$ for a period of 14 years, terminating on 31 October 1995. In the event that the Board were not prepared to grant the full licences, the Joint Applicants sought as an alternative a firm seven-year licence for $88\,701 \times 10^6 \text{ m}^3$ and a conditional volume for a further seven years of $77\,264 \times 10^6 \text{ m}^3$, terminating on 31 October 1994, with a further provision for a deficiency make-up year to 31 October 1995, the conditional volume to be reviewed at a public hearing within two years of the date of the licence, should the Board so direct.

2.8.1 Pan-Alberta

Pan-Alberta, owned 50.005 percent by AGTL and 49.995 percent by AEC, is a company incorporated under the laws of the Province of Alberta. Pan-Alberta currently purchases gas from various producers in Alberta and sells it primarily to Westcoast for export and to Gaz Métropolitain for delivery in the Montreal region.

The Joint Applicants, on behalf of Pan-Alberta, applied for two licences, seeking full 14-year terms for firm volumes over the whole period. However, in the event that the Board was not prepared to grant the full firm licence requested, as an alternative the Joint Applicants sought on behalf of Pan-Alberta a firm volume for a seven-year period and a conditional volume for the second seven-year period. In the latter case, it proposed that the conditional volume be reviewed at a public hearing to be held within two years of the date of the licences, wherein Pan-Alberta would be required to show cause why the conditional volume was necessary.

The first licence sought was for a full 14-year term commencing 1 November 1981 to export at Monchy, Saskatchewan a total firm quantity of $107\,600 \times 10^6 \text{ m}^3$. In the alternative, a licence was requested for a firm volume of $49\,653 \times 10^6 \text{ m}^3$ for a six-year period followed by a conditional or future firm volume of $57\,947 \times 10^6 \text{ m}^3$ for the remainder of the period. A daily volume of $24\,928.5 \times 10^3 \text{ m}^3$ and an average annual volume of $8\,294.4 \times 10^6 \text{ m}^3$ would apply in either case.

The second licence applied for was for a full 14-year term commencing 1 November 1980 to export at Kingsgate, B.C. a total firm quantity of $32\,280 \times 10^6 \text{ m}^3$ during the term of the licence. In the alternative, the Joint Applicants on behalf of Pan-Alberta sought a licence authorizing a firm volume of $17\,377 \times 10^6 \text{ m}^3$ over a seven-year period and $14\,903 \times 10^6 \text{ m}^3$ during the remainder of the fourteen-year period as conditional or future firm volumes. A daily volume of $7\,478.6 \times 10^3 \text{ m}^3$ and an average annual volume of $2\,488.3 \times 10^6 \text{ m}^3$ would apply in either case.

For both licences, the alternative option proposes the firm period would terminate on 31 October 1987, followed by a further seven-year conditional period to 31 October 1994, and a deficiency make-up year terminating 31 October 1995. In both the firm and alternative options, the total quantity of gas sought to be exported was the same, i.e., $139\,880 \times 10^6 \text{ m}^3$.

In a Notice of Motion by the Joint Applicants dated 25 June 1979, approval on behalf of Pan-Alberta was sought to permit exports at Emerson of "best-efforts" gas during the period 1 November 1980 to 31 October 1981, utilizing any spare capacity that might exist on the TransCanada system.

2.8.2 TransCanada

TransCanada, a company incorporated in 1951 by a Special Act of Parliament, operates a pipeline system extending from the Province of Alberta through the Provinces of Saskatchewan, Manitoba, and Ontario to the Province of Quebec. TransCanada delivers gas to United States buyers at several export points, including exports to Midwestern at Emerson, Manitoba under Licences GL-1, GL-18, and GL-39.

The Joint Applicants, on behalf of TransCanada, applied for a licence to export gas to Midwestern commencing on the date when the total quantity of gas authorized for export under Licence GL-1 has been delivered (May or June 1980) and ending on 14 December 1985. The proposed licence would authorize TransCanada to export to Midwestern:

- a) A daily volume of $6\,317 \times 10^3 \text{ m}^3$ and a combined total volume of $2\,096 \times 10^6 \text{ m}^3$ under the proposed licence and Licence GL-1 during the period 1 November 1979 to 31 October 1980;
- b) A daily volume of $6\,317.1 \times 10^3 \text{ m}^3$ and an average annual volume of $2\,096.3 \times 10^6 \text{ m}^3$ during the period 1 November 1980 to 31 October 1985;
- c) A daily volume of $6\,317.1 \times 10^3 \text{ m}^3$ and $278 \times 10^6 \text{ m}^3$ during the conditional period 1 November 1985 to 14 December 1985; and
- d) during the term of the licence, a firm volume of $11\,331 \times 10^6 \text{ m}^3$ and a conditional volume of $278 \times 10^6 \text{ m}^3$.

2.8.3 Consolidated

Consolidated, a company incorporated under the provisions of the Canada Corporations Act, is a wholly-owned subsidiary of Northern Natural. Consolidated applied for a licence to export gas at a point on the international boundary near Emerson, Manitoba or Monchy, Saskatchewan over a nine-year term commencing on 1 November 1980.

As in the case of Pan-Alberta, the Joint Applicants sought on behalf of Consolidated a nine-year full volume firm licence, but if the Board were not prepared to approve a firm licence for that term, Consolidated sought as an alternative a firm licence for a shorter period of five years. The proposed nine-year licence would authorize Consolidated to export:

- a) a daily volume of $5\,665.6 \times 10^3 \text{ m}^3$ from 1 November 1980 to 31 October 1985 and, during each of the next four years, a daily volume equal to 80, 60, 40, and 20 percent respectively of $5\,665.6 \times 10^3 \text{ m}^3$.
- b) an average annual volume of $2\,067.9 \times 10^6 \text{ m}^3$ from 1 November 1980 to 31 October 1985 and, during each of the next four years, an annual volume of 80, 60, 40, and 20 percent respectively of $2\,067.9 \times 10^6 \text{ m}^3$; and
- c) $14\,475.5 \times 10^6 \text{ m}^3$ volume during the term of the licence.

In the alternative, the Joint Applicants requested on behalf of Consolidated a five-year licence, for the period 1 November 1980 to 31 October 1985, to export a daily quantity of $5\,665.6 \times 10^3 \text{ m}^3$ and a term volume of $10\,340 \times 10^6 \text{ m}^3$.

CHAPTER 3
NATURAL GAS SUPPLY

3.1 Reserves

3.1.1 Introduction

Evidence filed by Applicants and Intervenors with respect to estimates of natural gas supply was given in a variety of Imperial and SI units both on a volume and energy basis. In order that estimates can be directly compared, the Board has, where necessary, converted data provided in volumetric units to energy units, assuming average gross heating values. Data as submitted are included in parentheses throughout the text.

For estimates of reserves additions, a higher heating value of 37.5 MJ/m^3 was used for Alberta and British Columbia and 36.5 MJ/m^3 for Saskatchewan and for the southern Territories. While the heating value applied to reserves additions in Saskatchewan and the southern Territories approximates the respective historical averages, the value used for Alberta and British Columbia is lower than that applicable to reserves found to date. This lower heating value reflects the expectation that new gas found in these two provinces will, on average, have a lower energy content than that of the currently established reserves.

The heating values applied to estimates of ultimate potential are approximate weighted averages of the heating values of gas discovered to date and those estimated for future reserves additions. These values are 38.5 MJ/m^3 for British Columbia and Alberta and 36.5 MJ/m^3 for Saskatchewan and for the southern Territories.

Intervenors' estimates of remaining reserves as of 31 December 1978, reserves additions for the forecast period 1979-2000, and ultimate potential of the conventional producing areas of Western Canada are compared in Tables 3.1.1.A, 3.1.1.B, and 3.1.1.C respectively.

3.1.2 Evidence of Applicants

Only two of the Applicants submitted reserves evidence encompassing more than their own supplies. The other eight Applicants adopted the Board's findings with regard to national supply contained in the Board's 1979 Gas Report.

Pan-Alberta

Pan-Alberta estimated the total remaining established reserves in Canada as of March 1979 to be 77.2 EJ (73.2 Tcf at 1000 Btu/cf), which is 7.5 EJ

Table 3.1.1.A

REMAINING RESERVES OF MARKETABLE NATURAL GAS
CONVENTIONAL PRODUCING AREAS OF WESTERN CANADA

31 December 1978

(Exajoules⁽¹⁾)

	<u>British Columbia</u>	<u>Alberta</u>	<u>Sask.</u>	<u>Southern Territories</u>	<u>Western Canada Total</u>
AERCB ⁽²⁾	—	64.7	—	—	—
CPA ⁽³⁾	8.5	60.2	1.3	0.6	70.6
B.C. Ministry of Energy, Mines and Petroleum Resources ⁽⁴⁾	7.8	—	—	—	—
Westcoast	8.0	—	—	—	—
NEB	7.6	64.4	1.4	0.3	73.7

(1) Gross heating values used in conversion, as necessary, to energy units:

British Columbia	38.8 MJ/m ³
Alberta	38.8 MJ/m ³
Saskatchewan	36.5 MJ/m ³
Southern Territories	36.6 MJ/m ³

(2) From AERCB Report 79-18

(3) Estimates from data published in CPA Statistical Handbook except for Western Canada total which was submitted in evidence.

(4) Estimates from data published in B.C. Ministry of Energy, Mines and Petroleum Resources report - Hydrocarbon and By-Product Reserves in British Columbia, 31 December 1978.

Table 3.1.1.B

MARKETABLE NATURAL GAS RESERVES ADDITIONS FORECASTS

CONVENTIONAL PRODUCING AREAS OF WESTERN CANADA

1979-2000

(Exajoules)

	<u>British Columbia</u>	<u>Alberta</u>	<u>Sask.</u>	<u>Southern Territories</u>	<u>Western Canada Total</u>
CPA	7.8	57.0	1.1	1.1	67.0
Dome ⁽¹⁾	---	---	---	---	---
Imperial	---	---	---	---	40.4
Shell	---	---	---	---	39.1 ⁽²⁾
Westcoast ⁽³⁾	7.4	---	---	---	---
NEB	6.6 ⁽⁴⁾	41.0	0.8	---	48.4

(1) Dome expects the 3.5 Tcf historical average annual additions rate to be extended for 10 years.

(2) May include minor allocation to Eastern Canada.

(3) Forecast to 1997 only.

(4) Includes southern Territories.

Table 3.1.1.C

ULTIMATE POTENTIAL ESTIMATES OF MARKETABLE NATURAL GAS

CONVENTIONAL PRODUCING AREAS OF WESTERN CANADA

(Exajoules)

	<u>British Columbia</u>	<u>Alberta</u>	<u>Sask.</u>	<u>Southern Territories</u>	<u>Western Canada Total</u>
AERCB	—	137-148 ⁽¹⁾	—	—	---
Amoco	—	205-235 ⁽²⁾	—	—	---
CPA	22	141-164-185 ⁽³⁾	3	2	168-191-212
Gulf	33	164	—	—	---
Imperial	22	136	—	—	163
NEB	21 ⁽⁴⁾	145	3	—	169

(1) From AERCB Report 79-B; AERCB estimated that with higher gas prices than currently anticipated and substantial technological breakthrough, the ultimate potential of Alberta could exceed 211 EJ.

(2) Amoco predicted an additional ultimate potential of 105-211 EJ for unconventional and higher cost gas in Alberta.

(3) At 95, 50 and 5 percent probability respectively.

(4) Includes southern Territories.

higher than the preliminary estimate of 69.7 EJ for year-end 1978 published in the Board's 1979 Gas Report. Pan-Alberta determined its estimate by adopting the estimates of reserves contained in the reports of provincial agencies for year-end 1977 and by adjusting those estimates for reserves additions and production during 1978 and early 1979.

For its forecast growth of marketable reserves from reserves additions in the conventional producing areas, Pan-Alberta adopted the Board's high case in the 1979 Gas Report. However, Pan-Alberta believed that for Alberta, the Board's high reserves additions case, which was based on an ultimate potential of 142 EJ for Alberta, was too conservative, particularly in light of the evidence submitted at AERCB's 1979 hearing concerning Alberta's ultimate potential. Pan-Alberta included in its application a summary of the various estimates of Alberta's ultimate potential that had been submitted to AERCB; these averaged 160 EJ (152 Tcf at 1000 Btu/cf¹).

Westcoast

Westcoast estimated that the remaining recoverable reserves of marketable gas were 8.0 EJ ($206.1 \times 10^9 \text{ m}^3$) in northeastern British Columbia and 0.3 EJ ($7.9 \times 10^9 \text{ m}^3$) in the southern Territories as of 1 January 1979. These volumes were, in total, 0.5 EJ ($14.0 \times 10^9 \text{ m}^3$) greater than Westcoast's corresponding estimates as of 1 January 1978 submitted at the 1978 Gas Inquiry.

Westcoast's forecast of reserves additions in northeastern British Columbia, i.e., 7.4 EJ ($197.1 \times 10^9 \text{ m}^3$), for the years 1979 through 1997, the last year of Westcoast's forecast, was unchanged from that submitted at the 1978 Gas Inquiry.

3.1.3 Evidence of Intervenors

Eleven intervenors submitted evidence on reserves, either on the basis of national supply or with respect to their own reserves.

Amoco

Amoco presented data, much of it statistical, with respect to reserves additions and ultimate potential.¹

The Company cited its submission to AERCB dated 15 December 1978, which concluded that the ultimate potential for conventional gas in Alberta was

(1) 1000 Btu/cf assumed.

205 to 235 EJ (194 - 223 Tcf at 1000 Btu/cf), with an additional ultimate potential of 105 to 211 EJ (100 - 200 Tcf at 1000 Btu/cf) for unconventional and higher cost gas. It stated that there was a significant amount of gas commercially available in low permeability reservoirs and urged the Board to give serious consideration to this resource when assessing long-term supply potential. It further recommended that the Board give due consideration to the "significant" reserves potential by-passed in the search for deeper horizons or abandoned because of economic conditions prevailing at the time of drilling.

Amoco contended that improved economics and technology would lead to the discovery of a large number of small pools. However, it would be incorrect, in the Company's opinion, to conclude that the discovery of small pools would mean fewer reserves in total being found or that no more large pools would be found.

Graphs were presented showing the relationship between natural gas reserves additions (volumes in-place) and drilling footage in Alberta for the period 1969 to 1977. From these graphs it was concluded there was no evidence that the rate of reserves additions was declining. Amoco contended that the Western Canada Sedimentary Basin was not sufficiently mature to permit its potential to be determined from extrapolation of drilling statistics.

Amoco provided recent drilling and test data on its reserves in the Windfall, Lennox, and Elmworth-Wapiti areas. It stated that a large increase had occurred in the Company's reserves in the Elmworth-Wapiti area since the data for this area were prepared for inclusion in the Pan-Alberta application.

Canadian Hunter

Canadian Hunter's intervention included a discussion and updates of reserves with respect to pools in the Gold Creek and Karr areas. The Company stated that the corresponding reserves estimates contained in the Pan-Alberta application had been made over a year previously.

Canadian Hunter's estimate of the established marketable gas reserves of the Elmworth-Wapiti area was greater than that presented at the 1978 Gas Inquiry. Proven reserves increased from 723 PJ (658 Bcf at 14.65 psia) to 1916 PJ (1744 Bcf at 14.65 psia). Of these, 1227 PJ (1117 Bcf at 14.65 psia), being in conglomerate zones and 689 PJ (627 Bcf at 14.65 psia) in sandstone zones. All but 121 PJ (110 Bcf at 14.65 psia) of these reserves were in the Cadotte or Fahler horizons. Canadian Hunter stated that it had experienced

encouragement from the successes in other horizons in the area, notably the Cadomin, Bluesky/Gething, and Halfway formations.

Canadian Hunter commented on an Elsworth area well in Township 71, Range 13, west of the sixth meridian, which was treated with a massive hydraulic fracture in 1978. The well did not contain any Fahler conglomerate. After the treatment, the well flow rate stabilized in 12 to 14 days at some 7.7 to $8.5 \times 10^3 \text{ m}^3/\text{d}$ (275 to 300 Mcf/d at 14.65 psia). Results were still under evaluation by the Company.

CPA

CPA's estimate of the established remaining reserves of natural gas in the conventional producing areas, including Eastern Canada, at the end of 1978, was 70.9 EJ (67.3 Tcf at 1000 Btu/cf), which was 3.2 EJ (3.0 Tcf at 1000 Btu/cf) higher than its corresponding estimate at the end of 1977. It recommended that the Board make use of new and updated information in determining the extent of a surplus.

CPA forecast reserves additions for Western Canada of 82.9 EJ (78.6 Tcf at 14.65 psia), of which 67.1 EJ (63.4 Tcf at 14.65 psia) would be realized in the period 1979-2000. Illustrative low and high cases of 2.1 EJ and 4.2 EJ (2 Tcf and 4 Tcf at 1000 Btu/cf) per year respectively for all of Canada, including the frontier areas, had been submitted at the 1978 Gas Inquiry.

CPA estimated an ultimate potential for Western Canada of between 168 and 212 EJ (154.8 and 195.8 Tcf at 14.65 psia), which incorporated Alberta estimates of 141 EJ (129.5 Tcf at 14.65 psia) and 185 EJ (170.5 Tcf at 14.65 psia) at 95 percent and 5 percent probability respectively. CPA's Western Canada total, based on a 50 percent probability estimate for Alberta of 164 EJ (151 Tcf at 14.65 psia), was 191 EJ (176.3 Tcf at 14.65 psia). CPA estimated the ultimate potential of British Columbia to be 22 EJ (20.3 Tcf at 14.65 psia), of Saskatchewan/ Manitoba to be 3 EJ (3.2 Tcf at 14.65 psia), and of the southern Territories to be 2 EJ (1.8 Tcf at 14.65 psia).

Chieftain

Chieftain presented evidence updating estimates of its reserves in the Sinclair area, which it had contracted to Pan-Alberta. The Company noted that 72 percent of its proved reserves, while contracted, were shut in awaiting the outcome of the Hearing and that a further 5 percent were not contracted. It expressed concern that the expertise of independent producers like itself would be lost without an early assured market.

Dome

Dome submitted a report entitled "North Elmworth Area, Alberta, Gas Reserves and Deliverability Study, May, 1979", prepared by T. Fekete and Associates Consultants Ltd. This report concluded that in the study area (Townships 72-75, Ranges 9-13, west of the sixth meridian), the established reserves of natural gas were 651 PJ (591.5 Bcf at 14.65 psia), of which 616 PJ (562 Bcf at 14.65 psia) were in zones other than the Fahler. Detailed reservoir data were presented in support of the estimates. The study indicated an additional potential in the study area of 285 PJ (260 Bcf at 14.65 psia) from reserves to be discovered by future drilling.

With respect to ultimate potential, Dome submitted that the Board's estimate for Western Canada adopted in the 1979 Gas Report was too low and should be increased to at least a range of 160 EJ to 171 EJ (152 Tcf to 162 Tcf at 1000 Btu/cf), with an expected value of 166 EJ (157 Tcf at 1000 Btu/cf). Dome's own estimate approached 200 EJ (190 Tcf at 1000 Btu/cf). Dome also considered the Board's projection of reserves additions used in the 1979 Gas Report to be "extremely pessimistic". Dome expected the historical average of 3.7 EJ (3.5 Tcf at 1000 Btu/cf) per year would be exceeded for at least five years and would be met, on average, over the next 10 years.

Gulf

Gulf endorsed the CPA ultimate potential estimate for Alberta of 164 EJ (151 Tcf at 14.65 psia), at 50 percent probability, stating that it agreed with the play-horizon method used by CPA for its determination. Gulf had submitted an estimate of 114 EJ (105 Tcf at 14.65 psia) for Alberta at the 1978 Gas Inquiry, but during that proceeding it stated that it was "more comfortable" with an estimate of 141 EJ (130 Tcf at 14.65 psia), and that it would be doing more work in order to determine an estimate of ultimate potential in which it had confidence. Gulf supported its previous estimate of ultimate potential of 33 EJ (30 Tcf at 14.65 psia) for British Columbia and urged the Board to reconsider its estimate of 19 EJ (18 Tcf at 1000 Btu/cf) published in the 1979 Gas Report.

As one example where active drilling in the last few years had added significant gas reserves, Gulf provided reserves details on its Hanlan Swan Hills pool.

Imperial

Imperial presented a revised estimate of ultimate potential of 163 EJ (155 Tcf at 1000 Btu/cf) for the Southern Basin, which it stated was an increase of 16 EJ (15 Tcf at 1000 Btu/cf) from that provided at the 1978 Gas Inquiry. Included in the estimate were 136 EJ (129 Tcf at 1000 Btu/cf) for Alberta and 22 EJ (21 Tcf at 1000 Btu/cf) for British Columbia. No gas reserves in the low-permeability rocks of the Deep Basin were considered, but the Company noted that with higher prices and improved technology, significant volumes of gas from this source might be available in the future.

Future reserves additions were estimated at 57 EJ (54 Tcf at 1000 Btu/cf), of which 40 EJ (38 Tcf at 1000 Btu/cf) would be added by the year 2000 compared with 33 EJ (31 Tcf at 1000 Btu/cf) forecast in 1978. Most of the increase was due to reassessment of the undiscovered potential of the Elsworth area and Cretaceous reservoirs in general. The Company's current forecast of discovery rates over the next five years was about 15 percent higher than predicted in 1978.

IPAC

IPAC expressed concern that the Board's estimate of established reserves at 31 December 1978 was low, and attributed this, at least partially, to the Board not having up-to-date data. IPAC recommended that the Board add 2.1 EJ (2 Tcf at 1000 Btu/cf) to its estimate of established reserves to compensate for the time lag in the Board's recognition of new reserves. IPAC considered that the Board's 1979 Gas Report was overly pessimistic in the assessment of future reserves additions, which it felt should be at least 3.2 EJ (3 Tcf at 1000 Btu/cf) a year for Alberta in the near term (three to five years) and expressed its belief that the Board's assessment of ultimate potential should be reviewed and adjusted upward, at the very minimum by 10.5 EJ (10 Tcf at 1000 Btu/cf).

Using three representative areas of Alberta, IPAC presented reserves data submitted by producers, showing that for those areas the reserves estimates of the producing industry exceeded those of the Board by 1 915 PJ (1,750 Bcf at 14.65 psia) in fields for which the Board had accepted the estimates of AERCB, and by approximately 1 169 PJ (1,068 Bcf at 14.65 psia) in pools for which neither the Board nor AERCB had any estimate. IPAC urged the Board to meet at an early date with those companies which provided IPAC with reserves data to discuss the differences in estimates.

Norcen

Norcen asked the Board to use actual reserves additions for 1978 and the first half of 1979, where available, when it makes its decision. In this regard, it provided the Board with its estimates of reserves additions, namely, 4 760 PJ ($127 \times 10^9 \text{ m}^3$) for 1978 and 2 140 PJ ($57 \times 10^9 \text{ m}^3$) for the first half of 1979. The 1978 estimate was based on preliminary data released by AERCB, British Columbia, and CPA. The estimate for 1979 was based on a comparison of 1979 and 1978 gas well completions.

Petro-Canada

Petro-Canada provided an estimate of the proved reserves of Melville Island, Northwest Territories, which was approximately $255 \times 10^9 \text{ m}^3$, with an energy content of 9 654 PJ. Petro-Canada related those reserves to its proposed Arctic Pilot Project, a proposal to transport LNG by tanker from Melville Island to a terminal on the east coast of Canada or the United States, or possibly in Europe.

Shell

Shell provided updated reserves data for four fields that it operates. The Company's forecast of reserves additions was the same as that presented at the Board's 1978 Gas Inquiry. These totalled 41.9 EJ (39.7 Tcf at 1000 Btu/cf) for the period 1978-2000, and 39.1 EJ (37.1 Tcf at 1000 Btu/cf) for the period 1979-2000. Of the 41.9 EJ, 8.4 EJ (8.0 Tcf at 1000 Btu/cf) were attributable to appreciation of reserves discovered prior to 1978. Shell noted, based on CPA data on reserves additions for the years 1969 to 1978, that, on average, appreciation of existing fields accounted for 83 percent of reserves additions.

3.1.4 Views of the Board3.1.4.1 Established Reserves

The Board's preliminary⁽¹⁾ and final estimates of the remaining established marketable reserves of natural gas for the conventional producing areas as of 31 December 1978 are compared in Table 3.1.4.1. In addition, the Board has made a preliminary estimate of the remaining established reserves for 31 December 1979 of 75.7 EJ, as shown in Table 3.1.4.1. This estimate is based on a projection of gross reserves additions to 31 December 1979 of 4.75 EJ.

(1) From the 1979 Gas Report.

Individual pool estimates are available for examination by interested parties at the Board's Geology and Reserves Office in Calgary.

Table 3.1.4.1
NEB ESTIMATES OF REMAINING ESTABLISHED RESERVES
OF MARKETABLE NATURAL GAS
CONVENTIONAL PRODUCING AREAS
(Exajoules)

	(preliminary) ⁽¹⁾ as of <u>1978-12-31</u>	(Final) as of <u>1978-12-31</u>	(preliminary) as of <u>1979-12-31</u>
British Columbia	7.0	7.6	7.8
Alberta	61.0	64.4	66.0
Saskatchewan	1.1	1.4	1.3
Southern Territories	<u>0.3</u>	<u>0.3</u>	<u>0.3</u>
Western Canada Total	69.4	73.7	75.4
Ontario	<u>0.3</u>	<u>0.3</u>	<u>0.3</u>
Canada Total	69.7	74.0	75.7

The total Canada estimate of 74.0 EJ at the end of 1978 is 4.3 EJ higher than the preliminary estimate of 69.7 EJ (66.1 Tcf) published in the 1979 Gas Report. A cumulative production adjustment for British Columbia by the provincial Ministry of Energy, Mines and Petroleum Resources accounts for 0.3 EJ of the difference. Saskatchewan reserves were increased by 0.3 EJ to include an additional portion of probable reserves, primarily in the south-western part of the province, in the established category. The remaining difference of 3.7 EJ of which 0.3 EJ applies to British Columbia and 3.4 EJ to Alberta, reflects the Board's review of individual pool reserves based on additional reservoir data available to the Board since the estimate in the 1979 Gas Report was made, and includes data submitted in evidence by Applicants and Intervenor, and those published by provincial regulatory agencies. During the review, it became apparent that the high level of exploratory and development activity during 1978 had resulted in a larger volume of reserves

(1) From 1979 Gas Report

additions than anticipated at the time of the 1978 Gas Inquiry. Furthermore, a quantity of gas in excess of 1 Tcf existing in pools discovered prior to 1978 was revealed through the detailed pool data submitted in evidence at the current hearing.

The Board generally has not included in established reserves gas in the so-called "tight" formations, i.e., gas in reservoirs with permeabilities too low to respond to conventional completion practices. The division between such reservoirs and those with higher permeabilities usually associated with commercial production is gradational rather than abrupt, and it is evident from current experience in Western Canada that production is possible with conventional technology from rocks having permeabilities lower than the generally accepted norm. To the extent such production is assured, the Board has included and will continue to include the supporting reserves in the established category.

3.1.4.2 Reserves Additions and Ultimate Potential

The Board has received testimony overwhelmingly in support of estimates of reserves additions and ultimate potential for the conventional producing areas, and Alberta in particular, in excess of those constituting the Board's expected case contained in the 1979 Gas Report.¹ The Board's forecasts have been termed pessimistic and upward adjustments have been urged.

The Board, in previous reports, has emphasized the judgemental nature of estimates of ultimate potential. That they are subject to change, often to a significant degree over a relatively short period of time, is clearly evident by the examination of testimony at recent Board hearings.¹ Taking Alberta as an example, estimates provided at the Board's 1974 Gas Hearing, ranged from 85 EJ to 134 EJ. At the Northern Pipelines Hearing in 1977, while evidence with respect to ultimate potential was very limited, the range from 107 EJ to 123 EJ did not suggest any material change in industry opinion. However, by 1978, as the effect on reserves additions rates of major increases in producer netback from gas sales became obvious, opinion changed radically. Studies were

tendered in evidence at the Board's 1978 Gas Inquiry, based both on statistical evidence and evaluation of geological prospects, in support of estimates as high as 211 EJ, although the majority fell in the range from 116 EJ to 137 EJ. At the same time, the Board was made aware of a very large potential for additional reserves in low permeability zones, a potential which previously had not been generally recognized.

Three submitters at the Board's 1978 Gas Inquiry (Gulf, Imperial, and AERCB) have since increased their estimates of ultimate potential. In testimony at the Board's current hearing, Gulf and Imperial submitted estimates for Alberta of 164 EJ and 136 EJ (151 Tcf at 14.65 psia and 129 Tcf at 1000 Btu/cf) respectively, compared with previous estimates of 112 EJ and 137 EJ (105 Tcf and 130 Tcf at 14.65 psia) and 120 EJ (114 Tcf at 1000 Btu/cf) previously. Imperial raised its British Columbia estimate as well, from 20 EJ to 22 EJ (19 Tcf to 21 Tcf at 1000 Btu/cf). AERCB increased its estimate for Alberta from 116 EJ (110 Tcf at 1000 Btu/cf) to between 137 and 148 EJ (130 to 140 Tcf at 1000 Btu/cf) following a recent hearing⁽¹⁾. In addition, CPA, whose last estimates of ultimate potential, submitted to the Board's 1974 Gas Hearing, included a range of 85 EJ to 134 EJ (79 Tcf to 125 Tcf at 14.65 psia) for Alberta, now considers that province's ultimate potential to be 141 EJ (129.5 Tcf at 14.65 psia) at the 95 percent probability level and 185 EJ (170.5 Tcf at 14.65 psia) at the 5 percent probability level, with a mean value of 164 EJ (151 Tcf at 14.65 psia). CPA also submitted a new estimate for British Columbia of 22 EJ (20.3 Tcf at 14.65 psia).

After considering this evidence, the Board has increased its estimate for the expected value of the ultimate potential of Alberta from 132 EJ to 145 EJ and that of British Columbia, including the southern Territories, from 19 EJ to 21 EJ. Its estimate for Saskatchewan of 3 EJ is unchanged. The estimated ultimate potential of the conventional producing areas of Western Canada is therefore 169 EJ compared with the previous estimate of 154 EJ. The addition of 1 EJ for Ontario gives a total ultimate potential estimate of 170 EJ for the conventional producing areas of Canada. (Note: In the context of a hearing of applications for the export of gas, the Board has employed a single forecast in lieu of a range of forecasts.)

The Board's forecast of annual reserves additions during the forecast period is included in Table 3.1.4.2 and Figures 3.1.4.2A, B. and C.

(1) AERCB Report 79-B.

Table 3.1.4.2

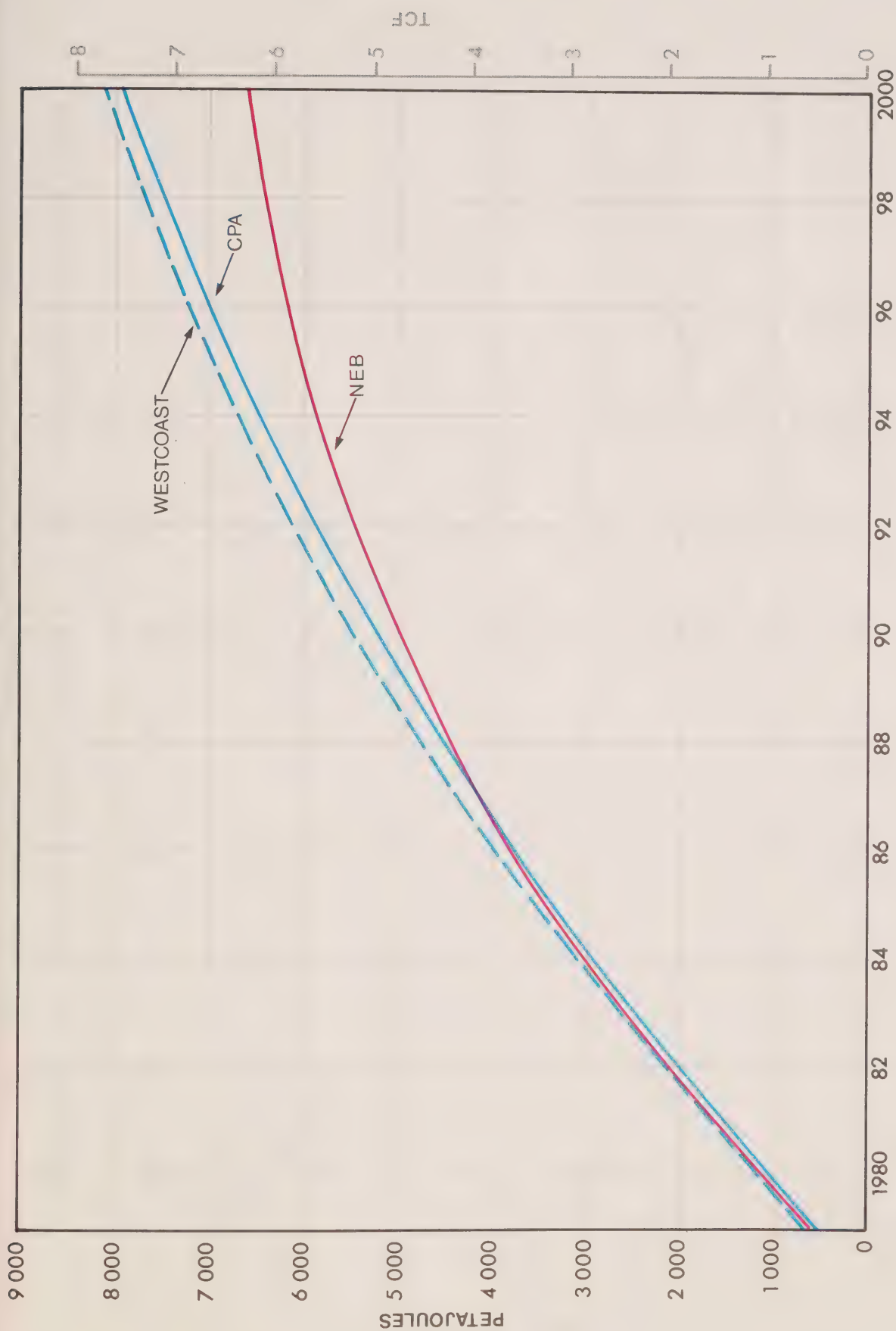
FORECAST OF MARKETABLE NATURAL GAS RESERVES ADDITIONS

1979 - 2000

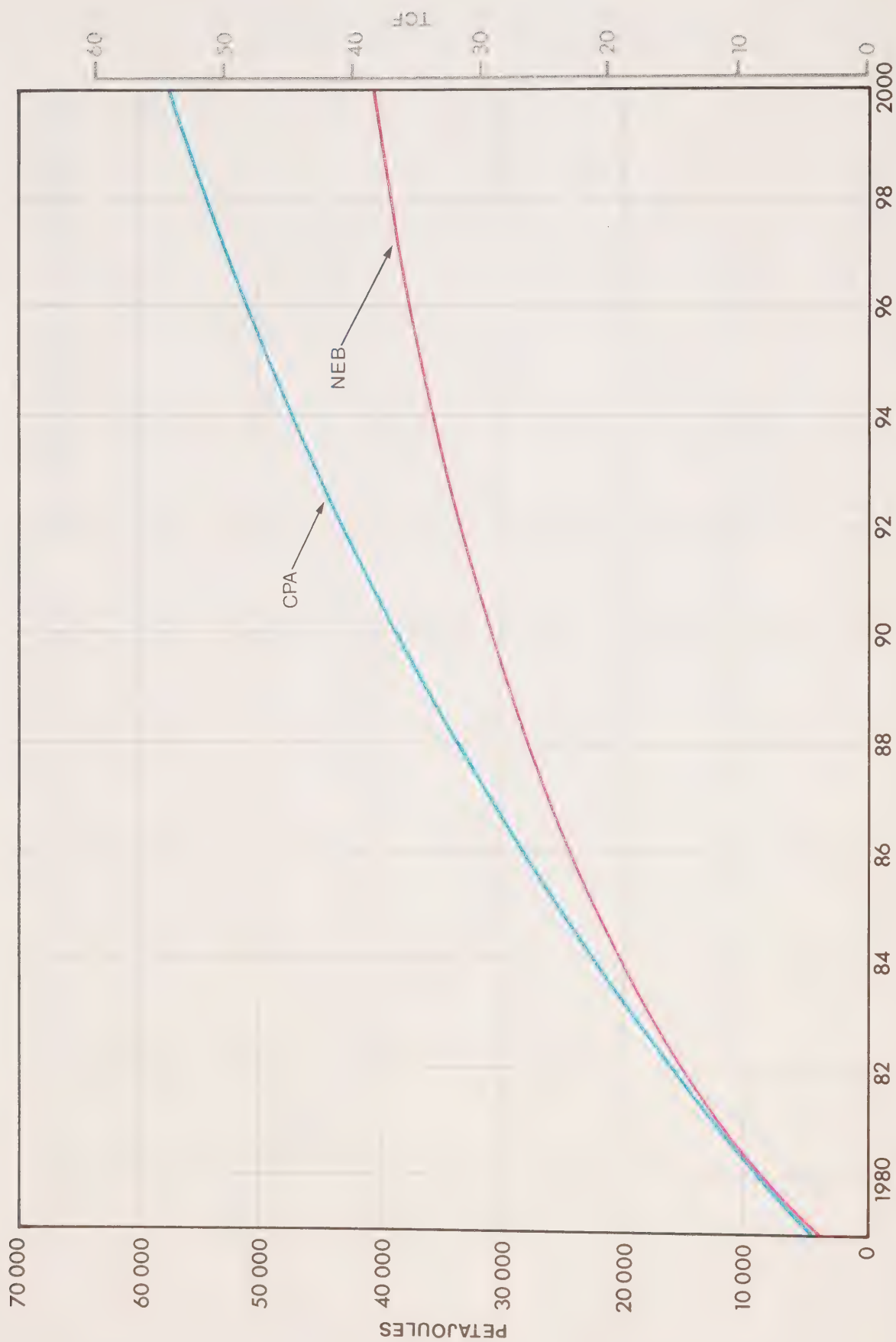
NEB Estimate

(Petajoules)

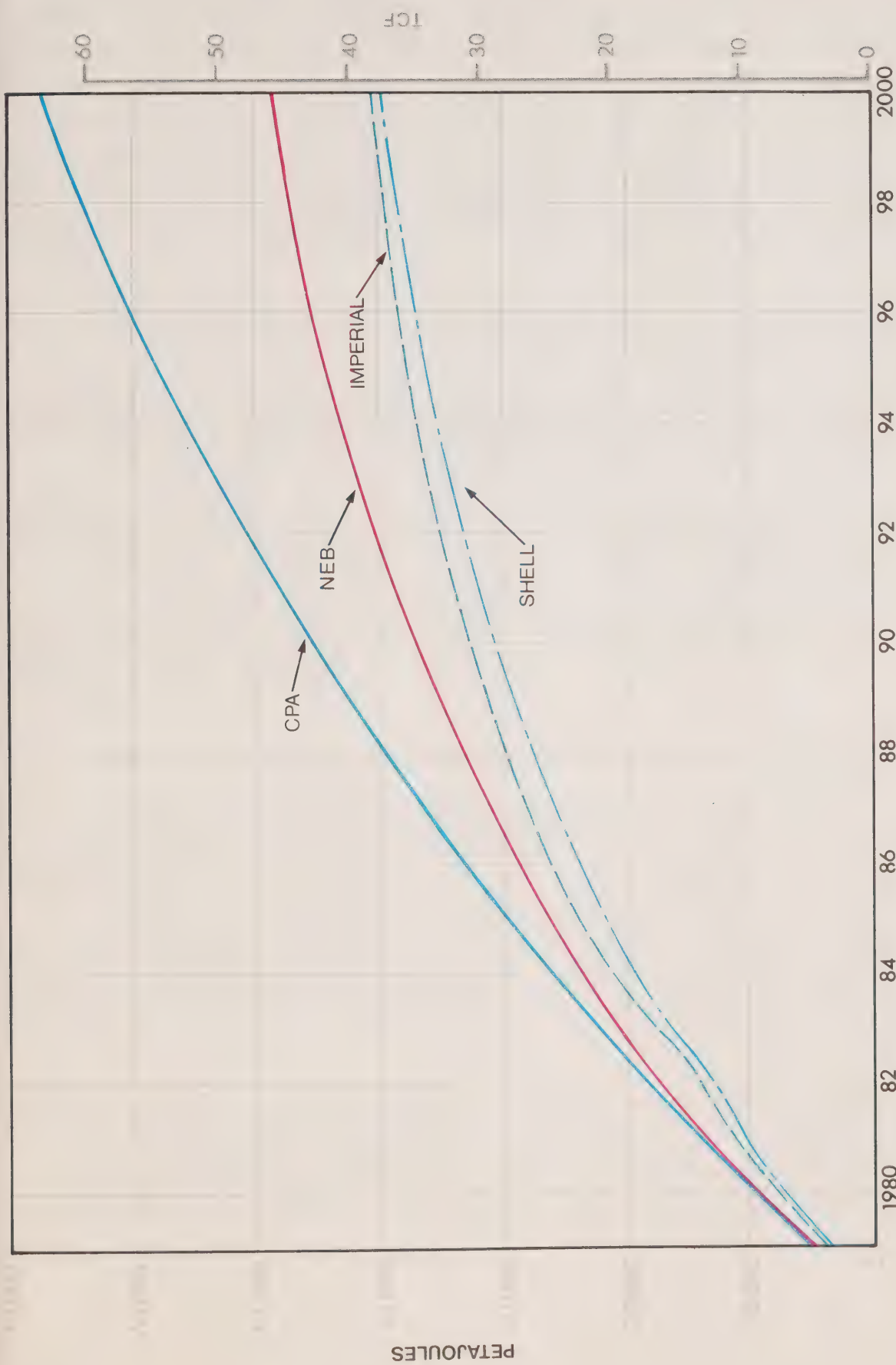
<u>Year</u>	<u>British Columbia</u>	<u>Alberta</u>	<u>Saskatchewan</u>	<u>Western Canada Total</u>
1979	530	4 200	20	4 750
1980	530	4 200	20	4 750
1981	520	3 700	20	4 240
1982	510	3 200	20	3 730
1983	500	2 700	20	3 220
1984	450	2 400	20	2 870
1985	400	2 200	60	2 660
1986	360	2 000	60	2 420
1987	320	1 800	60	2 180
1988	290	1 700	60	2 050
1989	270	1 600	60	1 930
1990	260	1 500	60	1 820
1991	250	1 400	60	1 710
1992	230	1 300	60	1 590
1993	210	1 200	60	1 470
1994	190	1 100	60	1 350
1995	170	1 000	40	1 210
1996	150	900	20	1 070
1997	130	800	20	950
1998	110	700	-	810
1999	110	700	-	810
2000	110	700	-	810
Total	6 600	41 000	800	48 400



FORECAST OF MARKETABLE NATURAL GAS RESERVES ADDITIONS
British Columbia



FORECAST OF MARKETABLE NATURAL GAS RESERVES ADDITIONS
Alberta



FORECAST OF MARKETABLE NATURAL GAS RESERVES ADDITIONS
Conventional Producing Areas of Western Canada

The Board's forecast of reserves additions has also been increased in recognition of the higher values of ultimate potential. The additional volumes are assumed to be added, for the most part, in the earlier years of the forecast period. Reserves additions in the conventional areas from 1979 through 2000 are now estimated to be 48.4 EJ, an increase of 8.3 EJ from the previous estimate.

Reserves additions for 1978 before deducting the year's production were 8.9 EJ. This is more than double the historical annual average of 3.7 EJ. Additions in 1977, before production, of 5.8 EJ were also well above the historical average. For the initial four years of its forecast period, i.e., from 1979 through 1982, the Board assumes additions rates in excess of the historical average, but not as high as those experienced during the past two years.

The forecasting of future reserves additions is even more uncertain now than in the past, owing in large measure to the emergence of the Deep Basin area, where very rapid discovery and development of new reserves have taken place, and resulting also from the recognition that small volume reservoirs and reservoirs with low productive capacities are potentially capable, in aggregate, of being large sources of natural gas. It is evident that more development and extended periods of production will be required before the magnitude of the contribution of these sources to future supply can be determined. In the meantime, the Board considers it prudent to adopt a reasonably cautious approach in its forecasting.

3.2 Deliverability

3.2.1 Introduction

Evidence concerning total Canada gas supply forecast was rather limited. Most Applicants and Intervenor chose to discuss the Board's deliverability forecasting methodology described in its 1979 Gas Report. The principal area of concern was the Board's methodology for forecasting deliverability from new reserves additions. Consequently, much of the evidence contained suggestions regarding connection rates and deliverability profiles for new reserves additions.

3.2.2 Evidence of Applicants

Westcoast

Westcoast's evidence was limited to the treatment of reserves and reserves additions in the British Columbia portion of its supply area. Except for the Graham and Junior-Sierra areas, the remainder of the connected reserves were added at 10 percent in 1981 and 1982, 9 percent in 1983, 8.1 percent in 1984, and so on, on a declining basis. The first year of connection for new reserves additions

was the fourth year after discovery. New reserves were produced at a rate of take of 1:5750⁽¹⁾ for five years followed by a five percent per year decline.

Joint Applicants

International Energy Consultants presented a detailed forecast of total Canadian supply capability on behalf of the Joint Applicants. The producing capability of established reserves was analysed, by purchaser, and totalled 3 473 PJ (3293 Bcf at 1000 Btu/cf) in 1979, growing to 4 601 PJ (4363 Bcf at 1000 Btu/cf) in 1982, then declining to 1 121 PJ (1063 Bcf at 1000 Btu/cf) by the year 2000.

The Board's high reserves additions forecast from the 1979 Gas Report was employed to give the total forecast of capability. New reserves additions were connected at 0, 10, 20, 20, 15, 15, 10, 5 and 5, percent per year commencing in the year of addition. These reserves were produced at a rate of take of 1:7000 until 40 percent depletion followed by a 10 percent per year decline thereafter.

The Joint Applicants' forecast of total capability commenced with 3 473 PJ (3293 Bcf at 1000 Btu/cf) in 1979, increasing to 4 955 PJ (4698 Bcf at 1000 Btu/cf) in 1984, then declining to 2 544 PJ (2412 Bcf at 1000 Btu/cf) by the year 2000.

3.2.3 Evidence of Intervenors

Amoco

Focusing on the 1979 Gas Report, Amoco was highly critical of the Board's forecasting methodology, although it appeared to lack an understanding of the basic assumptions and techniques employed in the Board's deliverability model.

Amoco disagreed with the Board's treatment of reserves additions. It stated that historically the appreciation component was in excess of 80 percent of reserves additions and as such should have connection rates vastly different from new discoveries. Amoco believed that a rate of take of 1:7300 was accep-

(1) The average rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which production is obtained. For example, 1:5750 means one cubic metre per day of production for each block of 5750 cubic metres of initial established reserves.

table and should be maintained until at least 50 percent depletion. It stated that foothills area reserves have averaged 12 to 15 years flat life, before production declined.

CPA

CPA stated that the Board should treat the appreciation of reserves separately from new discoveries and connect the reserves appreciation within five years of addition at a 1:7300 rate of take. CPA believed that foothills area reserves should commence decline after 50 to 60 percent depletion and the plains reserves after 50 percent depletion. A CPA study of 94 pools illustrated an average of 55.5 percent depletion before decline for reserves producing at a 1:7300 rate of take.

Gulf

Gulf stated that 75 percent of Alberta gas additions found in deep reservoirs could be connected by the fifth year and that 100 percent of Alberta shallow gas could be connected by the fourth year after additions are booked. It supported CPA's suggestions and recommended that reserves should be 50 percent depleted before commencement of decline is estimated to occur.

Imperial

Imperial recommended that new reserves be produced at a rate of take of 1:7300 until 50 percent depletion followed by a 9 percent per year decline. Imperial also studied the potential natural gas producibility in Canada. Its forecast commenced with 3406 PJ ($91.0 \times 10^9 \text{ m}^3$) in 1979, increased to 3881 PJ ($103.7 \times 10^9 \text{ m}^3$) by 1982, remained relatively constant until the end of the 1980's and declined to 2721 PJ ($72.7 \times 10^9 \text{ m}^3$) by the year 2000.

IPAC

Kloepfer and Associates prepared a study of connection rates and deliverability profiles on behalf of IPAC. Kloepfer's connection rates for reserves additions by area were weighted to account for the appreciation component of the new additions. The overall connections commencing in the year of addition were 25, 22, 15, 10, 6, 2, 5, 3, 1, and 2 percent of reserves per year with the remaining 9 percent reserves connected by the fifteenth year. Kloepfer recommended an 11-year flat life for reserves producing at a 1:7300 rate of take. IPAC did not adopt Kloepfer's recommendations and suggested a rate ten percent higher than 1:7300 (i.e., 1:6636) for nine years followed by a ten percent decline.

Norcen

Norcen adopted the IPAC connection rates for new additions. It recommended that five-sixths of the new reserves additions should produce on a reserves-based type of contract of 1:7300 for 11 years with a 10 percent decline thereafter. The remaining one-sixth of the reserves would produce under a deliverability-type contract with an initial rate of take of approximately 1:4380 for two years followed by an eight percent per year decline.

Shell

Shell stated that the connection rates for new reserves additions used by the Board in the 1979 Gas Report were reasonable for new discoveries. It believed that reserves appreciation should be treated separately, with nearly 100 percent of these reserves connected within two years. Shell agreed with the Board's connection rates for uncommitted reserves. Shell contended that a 1:7300 rate of take need not be taken as an upper limit and rates ten to twelve percent higher were possible. Shell stated that foothills area reserves should decline after 50 percent depletion and plains area reserves after 35 to 45 percent depletion.

3.2.4 Views of the Board

The Board employed its gas deliverability computer model to forecast the maximum deliverability from established reserves. The forecast of supply from reserves under the control of major gas purchases is presented in Table 3.2.4.1. The model performs a pool-by-pool analysis of gas deliverability as characterized by well flow characteristics, basic reservoir parameters, and daily contract rates. The model incorporates the producer forecasts for the solution and associated gas production available to the appropriate gas transmission system. The results for each of TransCanada, A&S, Westcoast (Licence GL-41 and GL-4 supply areas), Pan-Alberta (new permit fields), ProGas Sulpetro, Canadian-Montana, and Columbia are shown in the table.

The remaining components of the forecast of supply from controlled reserves were derived from the following sources:

- a. The forecast for the Alberta utilities prepared by International Energy Consultants for the Joint Applicants was considered reasonable as was Pan-Alberta's forecast of its AERCB Permit No. PA 74-1 fields; hence these were adopted.

Table 3.2.4.1

NEB FORECAST OF TOTAL CONVENTIONAL SUPPLY CAPABILITY FROM CONTROLLED RESERVES
(Petajoules/yr.)

Year	TCPL	A&S	West-coast GL-41	West-coast GL-4	Pan-Alberta PA 74-1	Pan-Alberta New	Alta. Utilities	Many Islands	Canadian Montana	Production East of Alberta	Columbia	ProGas	Sul-petro	Total
1980	1 949	645	495	50	120	354	377	34	19	74	14	78	28	4 235
81	1 947	628	536	42	106	378	370	30	19	70	14	80	28	4 246
82	1 945	597	524	35	93	380	358	26	17	68	14	104	28	4 187
83	1 920	565	506	30	81	413	345	23	15	65	14	109	26	4 112
84	1 780	528	498	25	71	377	321	22	15	60	14	109	25	3 843
1985	1 756	520	467	15	62	339	289	20	15	55	14	105	24	3 681
86	1 640	458	408	5	54	281	264	18	15	51	14	95	22	3 325
87	1 493	416	348	5	48	233	236	16	13	46	12	86	22	2 974
88	1 310	371	313	5	41	198	223	13	12	41	10	79	21	2 637
89	1 171	330	283	5	36	175	203	13	10	36	9	72	20	2 361
1990	1 051	300	255	5	32	151	188	12	9	34	8	63	20	2 127
91	928	266	226	5	27	129	175	11	8	30	3	58	19	1 884
92	853	239	194	5	24	116	164	10	7	26	1	51	20	1 709
93	769	214	171	5	21	105	171	8	7	25	1	40	18	1 555
94	680	191	154	5	19	94	164	7	6	20	1	33	16	1 388
1995	606	169	142	5	16	84	152	7	5	20	1	30	14	1 250
96	542	134	123	5	14	74	134	6	5	19	0	23	12	1 090
97	481	114	114	4	13	65	175	5	5	18	0	19	10	1 023
98	436	92	106	1	11	59	164	5	4	16	0	16	9	919
99	395	81	95	1	10	36	155	4	4	15	0	14	7	816
2000	358	72	85	1	8	31	140	4	3	13	0	12	5	733

- b. The Many Islands Pipelines and Saskatchewan production forecasts were adopted from the Saskatchewan Power submission at the 1978 Gas Inquiry.
- c. The forecast of production from Ontario was estimated by the Board based on production history.

It should be noted that non-contracted gas in British Columbia, as of 31 December 1978, was considered to be controlled by Westcoast for the purpose of the system analysis. Reserves additions for 1979 were treated as uncommitted reserves. In Alberta, reserves as of 31 December 1979, which were not included in the controlled reserves supply forecast, were classified into three categories - uncommitted, deferred, and beyond economic reach.

The Board estimates that there will be some 10.9 EJ of established uncommitted gas reserves in Alberta as of 31 December 1979 and a further 0.5 EJ to be treated as uncommitted in British Columbia. The rapidly growing inventory of new gas pools had made it virtually impossible to identify and allocate Alberta uncommitted gas reserves into the three categories employed in the 1979 Gas Report. Therefore, a new connection rate schedule was prepared for uncommitted gas reserves in both Alberta and British Columbia, using a single schedule that would not be inconsistent with the schedules contained in the 1979 Gas Report. The new schedule is illustrated in Table 3.2.4.2.

In the 1979 Gas Report, the Board estimated that there were 4.4 EJ of deferred gas reserves in Alberta. Some 1.6 EJ of these reserves are now treated as controlled reserves and are included in the appropriate component of the forecast. The remaining 2.8 EJ are not expected to commence production until 1996 or later. They are assumed to be connected according to the schedule for uncommitted reserves starting in 1996.

The Board has treated reserves beyond economic reach in the same way as in the 1979 Gas Report. Fifty percent of the Board's estimate of 2.5 EJ of gas reserves beyond economic reach were assumed to be available during the forecast period and were connected at a rate of four percent per year.

The deliverability profile employed for all uncommitted reserves and new reserves additions was adopted from the evidence of the Joint Applicants. The profile is based on a rate of take of 1:7000 until 40 percent depletion has occurred; thereafter, a rate of take which declines at ten percent per year is used. Such a profile is considered to be a fair representation of the overall

Table 3.2.4.2
 CONNECTION RATES FOR UNCOMMITTED GAS
 (percent)

<u>Year</u>	<u>Rate</u>
1980	15
81	15
82	15
83	15
84	15
1985	10
86	5
87	3
88	3
89	2
1990	1
91	1

rate for a mix of various types of reserves contracted at 1:7300 and reserves contracted under deliverability contracts with significantly higher initial rates. It also closely represents the ability of reserves contracted at a rate of 1:7300 to produce at rates up to ten percent higher for a portion of the year. The 1:7000 rate is also a close approximation of the British Columbia rate of 1:5750 with Westcoast's 0.833 overall load factor applied to it.

The Board has revised its methodology for connecting new reserves additions based upon the evidence presented at the Hearing. Appreciation was considered separate from new discoveries in developing the Board's new connection rate profile. A weighted connection rate schedule for new discoveries was derived from the percentage distribution of the Board's forecast of reserves additions and the connection rates by area shown in the 1979 Gas Report. A connection rate schedule that assumed that 100 percent of the reserves appreciation would be connected by the fifth year was also prepared. Historically, appreciation has accounted for approximately 80 percent of the gross reserves additions and new discoveries the remaining 20 percent. An overall connection rate schedule was prepared based on the connection rate profiles described above and assuming that the historical relationship between appreciation and

new reserves would continue. This schedule is illustrated in Table 3.2.4.3 and was used by the Board to forecast the connection of the reserves from the Board's gross additions forecast. The reserves additions were then forecast to be produced at a rate of 1:7000 until 40 percent of the reserves had been depleted and subsequently at rates which decline at 10 percent per year.

The Board's forecast of total Canada supply capability appears in Table 3.2.4.4 and is shown in Figure 3.2.4.4. The forecast commences with 4.3 EJ in 1980, peaks at 4.9 EJ in 1985, and declines thereafter to 2.5 EJ by the year 2000. It represents the Board's estimate of capability assuming annual production at annual capability levels.

Table 3.2.4.3

CONNECTION RATES FOR RESERVES ADDITIONS
(percent)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year after Addition	Appre- ciation	Weighted @ 80 %	(1) New Dis- coveries	Weighted @ 20 %	Total	(2) Connection NEB Rate
0	10	8	-	-	8.0	10
1	20	16	7.1	1.4	17.4	15
2	25	20	7.3	1.5	21.5	20
3	25	20	17.3	3.6	23.6	25
4	15	12	17.0	3.4	15.4	15
5	5	4	14.5	2.9	6.9	5
6	-	-	8.2	1.6	1.6	2
7	-	-	5.3	1.1	1.1	2
8	-	-	5.3	1.1	1.1	1
9	-	-	4.8	1.0	1.0	1
10	-	-	4.8	1.0	1.0	1
11	-	-	4.8	1.0	1.0	1
12	-	-	4.0	0.8	0.8	1
13	-	-	1.1	0.2	0.2	1

(1) Historically, appreciation of the existing reserves base has accounted for approximately 80% of the gross reserves additions while new discoveries accounted for 20%.

(2) In the light of the analysis in the first six columns and the evidence presented at the hearing, the Board has adopted the connection rates shown in Column (7).

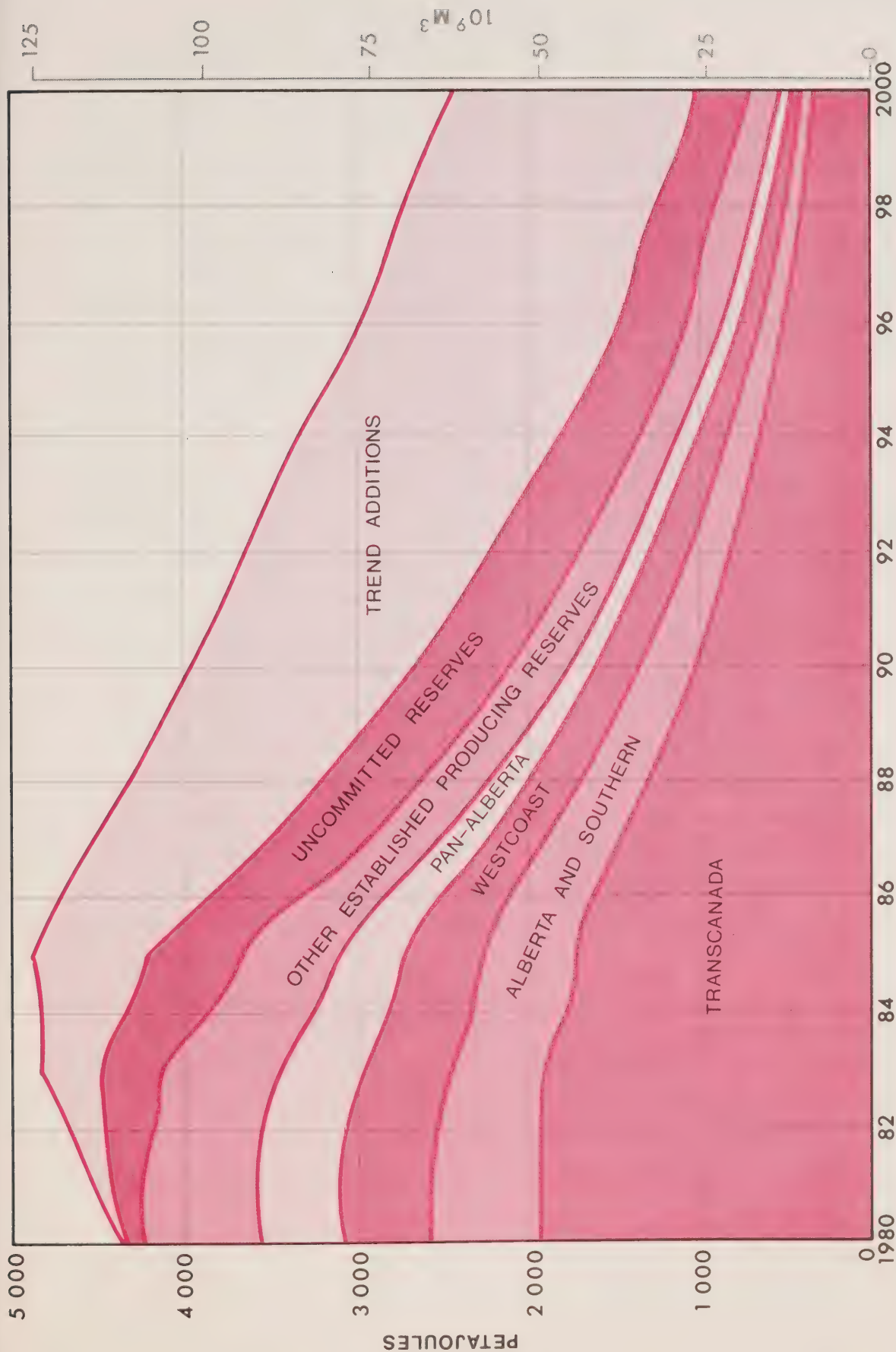
Table 3.2.4.4

NATIONAL ENERGY BOARD FORECAST

OF TOTAL CONVENTIONAL SUPPLY CAPABILITY

(Petajoules/yr.)

Year	Supply Capability from Established Reserves				Supply from Reserves Additions			Total Canada Supply Capability
	Total Controlled	Alberta Uncom- mitted	B.C. Uncom- mitted	B.E.R. Deferred	Total	British Columbia	Alberta Sask.	
1980	4 235	85	4	3	4 328	3	22	0
81	4 246	170	8	0	4 429	10	74	0
82	4 187	255	13	0	4 463	22	163	1
83	4 112	341	17	0	4 480	41	296	2
84	3 843	426	21	0	4 304	63	444	2
1985	3 681	482	23	0	4 202	86	584	4
86	3 325	510	24	0	3 878	108	710	5
87	2 974	525	25	0	3 545	129	827	7
88	2 637	534	25	0	3 219	148	931	9
89	2 361	528	25	0	2 940	164	1 023	12
1990	2 127	512	24	0	2 690	178	1 100	15
91	1 884	487	23	0	2 424	190	1 161	18
92	1 709	454	22	0	2 215	199	1 207	21
93	1 555	418	20	0	2 024	205	1 240	23
94	1 388	382	19	0	1 823	210	1 258	26
1995	1 250	348	17	0	1 650	212	1 264	28
96	1 090	315	15	10	1 465	212	1 260	30
97	1 023	285	14	20	1 379	210	1 248	32
98	919	257	13	30	1 255	207	1 227	32
99	816	231	12	40	1 136	203	1 200	32
2000	733	211	11	50	1 042	199	1 182	32
								2 456



SUPPLY CAPABILITY FROM CONVENTIONAL PRODUCING AREAS
N E B Forecast

CHAPTER 4
NATURAL GAS REQUIREMENTS

4.1 Introduction

As part of its 1978 Gas Inquiry, the Board conducted a detailed evaluation of energy demand by market sector and by fuel type. In preparing its estimates of both total energy demand and natural gas demand, the Board took into account the considerable amount of information that had been provided by the submitters at that Inquiry. The Board's review of that material included an assessment of a number of forecasts and their underlying assumptions. A summary of those forecasts and of the evidence, as well as a discussion of the Board's own estimates were subsequently presented in the 1979 Gas Report.

At the time of the preparation of that Report, the Board intended that the demand forecast presented in the Report would subsequently be used at this Hearing for purposes of determining the quantities of natural gas that would be surplus to Canadian requirements. In fact, all of the Applicants for licences to export natural gas adopted the Board's demand forecast, as did some of the intervenors who chose to address the matter of gas demand. However, the Board now holds the view, in light of events that have occurred since preparation of the 1979 Gas Report, particularly with regard to energy prices and economic activity, that it would be appropriate to review the demand estimates contained in that Report and to reassess some of the underlying assumptions used therein. Indeed, this view was supported by a few intervenors who submitted information with respect to revisions that had been made to their own previously-submitted forecasts, to reflect new forecast assumptions. This reassessment is summarized in Section 4.3.

4.2 Evidence

4.2.1 Demographic and Economic Growth

All of the Applicants adopted the Board's forecast of Canadian demand contained in the 1979 Gas Report. No data were therefore submitted by the Applicants with respect to possible changes in expected economic or demographic growth, which otherwise might have altered the demand estimates. Similarly, some intervenors indicated general acceptance or

adoption of the Board's forecast. However, several other intervenors stated that they had revised their estimates after reviewing the forecasts and assumptions they had submitted at the 1978 Gas Inquiry. Since these parties did not use a common format for the filing of their revised data, it was not possible to compare fully their assumptions.

Imperial

Imperial projected that real GNP would grow at an average annual rate of 3.5 percent until 1990, compared with its previous projection of 4.2 percent. This revised economic outlook reflected an assumed slower rate of growth in population and productivity. As a result, Imperial expected the level of economic activity in 1990 to be about nine percent lower than it had assumed in its submission at the 1978 Gas Inquiry.

Shell

Shell stated that real GNP was expected to increase at an average rate of approximately 3.1 percent per year from 1985 to 2000. This was approximately the same level of growth that it had assumed for the Gas Inquiry. At that time, its growth rate for GNP was on the low side of the range of growth rates projected by the submitters. Shell's revised data, however, did indicate that a lower rate of growth in population should be expected, compared with its previous estimates.

4.2.2 Energy Prices and Interfuel Competition

Many of the parties who participated in the Licence Phase of the Hearing expressed concern that assurances be given regarding the availability of adequate supplies to meet present and future domestic requirements, and expressed concern regarding future energy prices. The impact of changing energy prices is felt two ways. While prices influence the overall level of demand for total energy, relative prices are major determinants of the market shares held by the competing energy sources. Although most parties did not supply specific information regarding energy demand forecasts, some did observe that rapidly increasing oil prices and uncertainties regarding future oil supply could result in increased substitution of natural gas for oil.

TransCanada

TransCanada assumed a continuation of the present relationship of natural gas prices to those of oil in filing its estimates of basic deliveries. TCPL's estimates of delivery requirements were derived from and based on the same economic considerations and the same forecast of retail sales in the provinces as had been submitted at the 1978 Gas Inquiry. These estimates also reflected the assumption that no extraordinary measures would be introduced to achieve greater penetration of existing markets.

In addition to basic deliveries, TCPL also filed estimates of "self-reliance" volumes that included limited market expansion in Manitoba and Ontario, which might occur if incentive pricing mechanisms were introduced. These volumes were predicated on the assumption that certain incentives would be available to gas utilities to permit them to increase their sales to residential and commercial markets only. Although TCPL testified that there was a good likelihood that the utilities could also further penetrate the large industrial market, such potential sales were not included in its self-reliance estimates.

Westcoast

For its forecast of British Columbia demand Westcoast assumed an 85 percent price relationship of gas versus oil. While the current price relationship in British Columbia was shown to be approximately 55 percent, it was indicated that natural gas would still retain some price advantage over both oil and electricity and thus continue to be a preferred source of energy, if priced at 85 percent of domestic crude oil. Westcoast assumed that the relative prices of gas, oil, and electricity would remain constant throughout the forecast period, once natural gas reached the 85 percent price relationship with oil.

Imperial

In its submission at the 1978 Gas Inquiry, Imperial had assumed that real world oil prices would remain relatively constant. In its submission at this Hearing, Imperial's revised forecast took into account higher real energy prices caused by the recent world oil price increases. With respect to domestic oil prices, Imperial assumed that Canadian crude oil would reach world levels by 1985. It also assumed that natural gas prices in existing markets would continue to be set on the basis of 85

percent of the crude oil price at the Toronto city gate (the "Toronto Reference Price"). Imperial stated that the competitiveness of natural gas in existing market areas would not vary significantly over a price range for natural gas of 75 to 100 percent of the price of crude oil. Imperial added that its projections included substantial substitution of natural gas for oil in both the Ontario and Quebec markets. It projected an acceleration in the capture rate of natural gas customers, but expected that this would be more or less offset by decreased consumption as a result of conservation measures.

Shell

Shell assumed that world oil prices would experience a real increase of one percent to one and a half percent per year from 1985 to 2000, whereas in its submission at the 1978 Gas Inquiry, Shell had assumed that world oil prices would increase at seven percent per year in current dollars. Shell also assumed that Canadian crude oil would achieve price parity with world oil by 1983 and that natural gas would be priced at 85 percent of crude oil.

4.2.3 Forecast of Total Energy Demand

With respect to Canadian requirements, the main thrust of evidence at the Hearing was in regard to the demand for natural gas, rather than for total energy. The factors influencing gas demand were more specifically the subject of review, although some information was provided by intervenors regarding their total energy demand forecasts.

Imperial

Imperial's total energy demand forecast had been reduced because of a lower projection of economic growth and because higher prices were expected to increase energy conservation. Compared with its submission at the 1978 Gas Inquiry, Imperial's revised forecast was about seven percent lower for 1990 and about fifteen percent lower for the year 2000. Imperial's new estimates implied an average annual growth rate of about 2.1 percent over the forecast period.

Shell

Shell stated that its forecast of total energy demand indicated a lower rate of growth for energy in general in the 1990's, as compared with the 1980's. This reflected Shell's assumptions that population and GNP would grow at lower rates in the latter part of the forecast period.

4.2.4 Forecast of Natural Gas Demand (Existing Markets)

Although none of the Applicants submitted a forecast of total Canadian demand, some did provide forecasts of gas requirements for their own specific markets. For example, Westcoast submitted a demand projection for British Columbia, and TCPL provided estimates of its mainline requirements. Nevertheless, for forecasts of total Canadian gas demand for purposes of showing that a gas surplus existed, all Applicants chose to adopt the Board's forecast of Canadian demand, as presented in the 1979 Gas Report. Some intervenors provided evidence regarding revisions to the demand forecasts submitted at the 1978 Gas Inquiry.

TransCanada

TCPL's forecast of its basic requirements was based on its demand forecast submitted at the 1978 Gas Inquiry. (TCPL's forecast for that Inquiry indicated an average annual growth rate of 2.6 percent for the combined requirements of Saskatchewan, Manitoba, Ontario, and the existing market area of Quebec). Its estimates of basic deliveries were regarded as conservative by TCPL because their attainment did not depend upon governmental or other initiatives beyond those now in effect.

TCPL testified that it was not aware of other market situations, like that outlined by Kingston PUC, where sales volumes might increase by 19 percent over the next two years. TCPL stated that it was becoming fairly common for potential gas users to enquire about the availability of gas and indeed to request service and observed that, currently, the level of applications for service was higher than it had been in the recent past. TCPL cautioned, however, that the effect of conservation was also greater than previously expected and that the two were tending to cancel each other out in terms of market growth. Another offsetting aspect indicated by TCPL was that, as oil and gas prices rose, it was becoming apparent that more industries were looking at the use of coal as a possible alternative. Accordingly, TransCanada did not consider its forecast to be low for the first two years or so. Starting in about the third year, however, TCPL expected that more gas would be delivered to the Canadian market than indicated by the forecast contained in its application.

Westcoast

Westcoast's forecast of British Columbia demand was somewhat reduced from the forecast it submitted at the 1978 Gas Inquiry. Although it reflected a lower growth rate than previously anticipated for the B.C. Hydro service area, Westcoast's forecast of demand indicated a continuation of relatively strong growth in all service areas of the Province.

Gulf

Gulf stated that the major revisions to its natural gas requirements forecast were in the non-energy sector and in the addition of volumes for gas market expansion into areas not now served by gas. Its previous submission did not provide for such market expansion. After a review of potential developments in the petrochemical sector over the forecast period, Gulf stated that it had reduced its forecast of the number of gas-based ethylene plants from five to four. Gulf's forecast implied an average annual growth rate of about 3.2 percent for the years 1979 to 2000, compared with approximately 3.3 percent contained in its submission at the 1978 Gas Inquiry.

With respect to interfuel competition in the Ontario market, Gulf stated that preliminary data for the first five months of this year indicated that the demand for No. 2 fuel oil would be down and, furthermore, that demand for No. 6 fuel oil would be less than Gulf had estimated in its submission at the 1978 Oil Inquiry. The decline in demand for No. 6 oil was largely attributable to a decrease in demand by Ontario Hydro.

Imperial

Imperial made three important assumptions that influenced its projection of natural gas demand. Imperial assumed for the existing market area that natural gas would maintain its competitive position versus oil products and would continue to increase its market share. Imperial also assumed that gas service would be extended to the Quebec City area; and, finally, it assumed that natural gas prices would rise with Canadian crude oil prices and that these higher prices would induce significant additional conservation by consumers. Imperial's forecast⁽¹⁾

(1) Includes market expansion volumes which were not separately quantified.

showed net sales of natural gas to increase from $42.27 \times 10^9 \text{ m}^3$ (1,492 Bcf) in 1978 to $69.04 \times 10^9 \text{ m}^3$ (2,437 Bcf) in the year 2000. This implied an average annual growth rate of about 2.3 percent, as compared with 3.2 percent in its previous submission.

According to Imperial, the major reasons for the decrease in expected sales were that the lower rate of economic activity would result in slower energy growth in the commercial and industrial sectors; that higher gas prices would induce greater conservation; that new large commercial buildings would reflect increased emphasis on internal heat management, therefore requiring only modest amounts of supplemental heat; and that gas consumption to generate electricity in Ontario had been reduced.

Shell

Shell submitted an updated forecast of natural gas net sales. However, in contrast to the decreased growth rates indicated by Gulf and Imperial in their forecasts, Shell's new estimates of total net sales had been increased in comparison with its submission at the 1978 Gas Inquiry. (For purposes of comparison, Shell's forecast at that time was somewhat lower than the forecasts of Gulf and Imperial. It had projected an overall growth rate of approximately 2.8 percent, while Gulf and Imperial had projected 3.4 percent and 3.2 percent, respectively, for the period 1978 to 2000). Shell increased its forecast in all market sectors, except for thermal generation, for which the volumes were considerably reduced. Shell's revised forecast⁽¹⁾ implied an average annual growth rate of about 3.0 percent, with net sales forecast to increase from 1 590 PJ (1,508 trillion Btu's) in 1978 to 3 040 PJ (2,882 trillion Btu's) in the year 2000.

Shell's increase in demand in the residential sector reflected changes made to its assumptions regarding provincial population, households, and housing scrappage rates. Demand in the commercial sector was increased marginally compared with its previous forecast. A large part of the increase in demand in the industrial sector was assigned to Alberta, where Shell included certain volumes of gas for oil sands operations. The volumes were added because the 1978 AERCB report⁽²⁾

(1) Includes market expansion volumes which were not separately quantified.

(2) AERCB Report 78-I

had indicated there would be a continuing demand for gas for oil sands plants, whereas previous reports had indicated that this demand would terminate about 1985. Shell's total industrial forecast also reflected a change in the economic activity variable it used in forecasting industrial energy demand in Canada. In the thermal sector, Shell's forecast of gas requirements was reduced to reflect, for the most part, reductions by Ontario Hydro, but also to reflect expected reductions in British Columbia, Alberta and Saskatchewan.

Regarding competition with oil, Shell stated that data for Ontario for the first half of 1979 indicated that demand for No. 6 fuel oil in the industrial sector would be lower than Shell's previous estimates by about five or six thousand barrels per day on average for the year. With regard to the residential sector, Shell expected a declining use of heating oil, although no specific figures were available.

Norcen

Norcen testified that the biggest single problem facing its utility companies at the present time was trying to keep up with conservation. Although many new customers were being added, no significant amount of real growth was being achieved in sales per se.

Kingston PUC

Kingston PUC indicated that it was receiving an increasing number of requests from domestic, commercial, and industrial customers to convert from oil to gas. It said that should all those requests be met, the increase over its 1978 gas sales by the end of 1980 would be in excess of 19 percent.

4.2.5 Expanded Markets for Natural Gas

It was commonly agreed among the Applicants and intervenors that provision for natural gas demand in expanded markets should be included in the Board's estimates of total Canadian requirements prior to calculating the surplus that would be available for export.

TransCanada

TCPL filed estimates of sales that included certain market expansion in Manitoba and Ontario starting in the year 1980-81. These estimates were based on the assumption that certain incentives would be available to the utilities to enable them to increase sales in the

residential and commercial sectors. No provision was made for the industrial sector, although it was stated by TCPL that there was certainly a potential for additional sales in that sector as well.

Westcoast

Westcoast submitted estimates of the demand for natural gas that would be expected to result from extension of gas service to Vancouver Island starting in 1983. These estimates were considered by British Columbia to adequately represent potential natural gas demand on the Island.

Intervenors

The demand forecasts submitted by Imperial and Shell included volumes for market expansion in Quebec but not in the Maritimes. Similarly, Gulf also had indicated that its revised forecast of gas demand made allowance for expansion to the Quebec City area; its previous forecast had not included this expansion market. Some intervenors including Quebec, agreed that the market expansion volumes as estimated by the Board in the 1979 Gas Report should be used for purposes of considering the export applications. Nova Scotia stated that its current forecast of market penetration by gas, submitted at the 1978 Gas Inquiry, was somewhat more optimistic than was the Board's forecast, and that it expected to provide the Board with an update on demand in Nova Scotia for the Certificate Phase of the Hearing. B.C. Hydro had suggested that the Board should make allowance for volumes similar to those estimated by B.C. Hydro in its submission at the 1978 Gas Inquiry.

A number of intervenors also encouraged the Board to consider setting aside volumes for gas expansion in other areas, over and above the volumes allowed for the Eastern Canada expansion.

4.3 Conclusions

In the reassessment of its 1979 Gas Report forecast, the Board has taken into consideration the evidence provided at the Hearing and has developed revised estimates of demand in the light of current information and new assumptions. The details of the Board's revised forecast are presented and discussed in Appendix C.

One of the major assumptions underlying the Board's energy demand forecast is that Canadian oil prices will eventually reach

international levels. The Board has revised its projection of world oil prices, as a result of rapid increases by OPEC, increases that, in fact, were higher than originally announced by the OPEC nations earlier in the year. The effect of this on the domestic market is that the prices of Canadian crude oil and, consequently, natural gas are expected to escalate much more rapidly than had been assumed in the 1979 Gas Report.

In addition to considering the restraining influence of rapidly escalating energy prices on energy demand, the Board has also considered the disappointing performance of the Canadian economy. Furthermore, the Board has taken into account the influence on the Canadian economy of a generally expected weakness in the United States economy, for the next two years or so. As a result, the Board's forecast reflects a less optimistic outlook, in the short term, for the Canadian economy than its earlier forecast.

The Board recognizes that markets for natural gas in other regions besides Quebec and the Maritimes may expand. The Board has therefore included estimates of additional sales for Manitoba and Ontario that would occur as a result of possible incentive pricing mechanisms, and also included estimates of volumes that would be expected to result from extension of gas service to Vancouver Island.

Higher real energy prices and slower economic and demographic growth have had the effect of lowering the gas demand forecast. However, the inclusion of additional volumes for expanded markets, over and above the volumes allowed for in the 1979 Gas Report, would have a partial offsetting effect. The net impact of these factors, as well as other factors which were considered by the Board in reviewing its forecast, is that the new estimate of total gas demand is only slightly lower than the previous estimate for the first few years. However, for the longer term, the new forecast reflects a more noticeable change. It is 4.4 percent lower by 1990 and 7.2 percent lower by the year 2000. Table 4.3.A compares the Board's revised forecast of natural gas demand with its previous forecast, as published in Appendix 4-A of the 1979 Gas Report.

Table 4.3.A
TOTAL CANADIAN DEMAND FOR NATURAL GAS*
Comparison of NEB Forecasts
(Petajoules)

	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
1979 Gas Report	2 067	2 536	2 845	3 280	3 793
Licence Phase	2 022	2 478	2 719	3 085	3 519
Percentage Change	2.2	2.3	4.4	5.9	7.2

*Includes total net sales, fuel and losses and reprocessing shrinkage.

Inasmuch as the revised forecast is not significantly different from the 1979 Gas Report forecast in the near-to-medium term, the Board concludes that for purposes of the surplus determination, it will employ the demand forecast contained in the 1979 Gas Report, as produced in Table 4.3.B. As noted previously, this was originally the Board's intention at the time of the 1979 Gas Inquiry. Furthermore, this approach would be consistent with the position taken by all the Applicants and some of the intervenors at this Hearing in adopting the Board's forecast from that Report. Although the differences are minimal in the earlier years, the Board notes that the use of the 1979 Gas Report forecast, with its higher estimates in the longer term, provides a greater degree of protection of Canadian requirements. Such additional protection does not appear inappropriate, particularly in the light of the uncertainties regarding the effect on natural gas demand of increasing Canadian oil prices and regarding also the effects of the concern over oil supply. Uncertainties with respect to the impact of specific policies and incentives that might be introduced to expand the markets for natural gas also suggest that the Board use the higher forecast.

Table 4.3B
TOTAL NET SALES OF NATURAL GAS
INCLUDING EXPANDED MARKETS FOR EASTERN CANADA
NEB 1979 GAS REPORT FORECAST
(Petajoules/Year)

Year	Atlantic Expansion	Quebec	Quebec Expansion	Ontario	Manitoba	Sask.	Alberta	British Columbia	Total Canada
1980	0	101	0	750	74	108	509	167	1708
81	0	104	15	770	75	110	530	176	1779
82	17	106	31	789	77	111	545	186	1861
83	26	109	47	809	78	113	571	197	1950
84	35	114	64	838	81	116	584	210	2043
1985	44	118	82	866	84	119	605	224	2143
86	46	122	93	887	86	122	598	230	2183
87	48	127	104	908	88	125	608	235	2243
88	50	131	115	928	90	128	632	241	2314
89	51	136	126	950	92	131	642	246	2375
1990	53	141	139	976	94	135	652	252	2443
91	55	146	145	1000	97	138	662	262	2505
92	56	152	152	1030	99	143	674	272	2578
93	58	157	159	1063	102	148	701	283	2672
94	60	164	166	1099	105	154	713	295	2756
1995	61	171	175	1137	109	161	726	308	2847
96	63	178	179	1175	112	169	734	320	2929
97	64	186	185	1216	115	178	742	333	3019
98	66	194	190	1260	118	188	750	348	3116
99	67	204	194	1306	122	200	758	363	3215
2000	69	213	200	1354	126	213	765	380	3319

CHAPTER 5EVIDENCE IN REGARD TO THE APPLICATIONS5.1 Alberta and Southern5.1.1 Supply, Deliverability and Requirements5.1.1.1 Evidence

Alberta and Southern submitted detailed estimates of reserves for those pools within Alberta for which it had gas purchase contracts. These estimates indicated that the remaining reserves after production to 31 December 1978 were 8.824 EJ ($220.9 \times 10^9 \text{ m}^3$).

Alberta and Southern's evidence showed that it had entered into long term gas purchase contracts with producers in Alberta, and that the contracts were of both deliverability and reserves-based types. Some of those gas purchase contracts would terminate on 30 June 1987, but Alberta and Southern stated that it was negotiating to extend them, and that two of these extension contracts had already been executed. Also virtually all other suppliers had given assurances that such contract extensions could be negotiated.

Alberta and Southern holds AERCB Permit No. AS 71-6 (as amended) with authorization to remove 1 641.6 TJ (1,503.4 MMcf at 14.65 psia) daily and 541.6 PJ (496.0 Bcf) annually, for a total of 12 287 PJ (11,253 Bcf) ending 31 October 1995.

Alberta and Southern provided a study of the deliverability of its present total contracted supply and its most likely requirements. The results are shown in Table 5.1.1. The supply profile depicts the capability at any time assuming production only to the level of the lesser of the requirements or the capability at the same time.

The study was based on remaining committed reserves of 8.824 EJ ($220.9 \times 10^9 \text{ m}^3$) as of 31 December 1978, and assumed full economic development (both by the drilling of infill wells and the addition of compression) to try to maintain the daily rates of its current gas purchase contracts, totalling 1 750.9 TJ ($43.831 \times 10^6 \text{ m}^3$). The contracted supply included fields not listed in Alberta and Southern's removal permit but used in meeting non-permit requirements within Alberta.

Although the study showed that the remaining reserves base was adequate in terms of quantities available to depletion, the deliverable supply would be insufficient to meet the total annual requirements over the period 1982-89. Without the proposed sale to Pan-Alberta, supply was stated to be capable of tracking the reduced requirements until sometime in 1987. Evidence was adduced to show that the additional reserves necessary to forestall the maximum shortfall, which would occur in 1988, would be in the order of 1.6 EJ (1.4 Tcf at 14.65 psia) based on a 1:7300 rate of take. A & S also stated that it expected that there would be future net appreciation of reserves under presently contracted lands. Although these expectations were not quantified, Alberta and Southern indicated that, in any event, it would take all necessary steps to meet any shortfall.

Alberta and Southern estimated that its requirements for the period 1 January 1979 to 31 December 2000 including pipeline fuel, liquids extraction at Cochrane, and Canadian sales were 7 106.3 PJ ($177\,894.3 \times 10^6 \text{ m}^3$). These requirements included the proposed exports to PGT of 801.2 PJ ($20\,673.9 \times 10^6 \text{ m}^3$), which would be made under the extensions sought to Licences GL-3 and GL-35 between 1985 and 1989. They also included contracted sales to Canadian-Montana, which would be exported under Canadian-Montana's current Licences GL-5, GL-17, GL-25 and GL-36 as well as Canadian-Montana's applied-for exports of 138.7 PJ (127.8 Bcf at 14.73 psia). Not including the conditional sales to Pan-Alberta, some 939.9 PJ of the indicated requirements shown by Alberta and Southern are sales which are conditional upon export authorizations arising from the present proceedings.

A & S estimated that about 1 537.6 PJ ($34\,094.8 \times 10^6 \text{ m}^3$) of the forecast requirements would be for sales or use in Canada. Only a relatively small portion of those quantities would be conditional upon the Board granting the subject export applications. The reduced Canadian sales or use would be reflected in reduced requirements by AGTL for pipeline fuel, and by reduced liquids extraction at Cochrane arising from the lower throughput of gas volumes at that plant.

Alberta and Southern stated that remaining reserves dedicated to it under existing gas purchase contracts exceeded its forecast requirements including the proposed new export volumes.

With respect to the Board's tests to determine surplus, Alberta and Southern stated that the Current Deliverability Test did not apply in its case since it was applying for extensions to existing licences and was not requiring supply from surplus current deliverability. Alberta and Southern stated that it adopted the Board's calculation of current reserves surplus as shown in the 1979 Gas Report and that it was prepared to accept licences conditioned in such a way that only those quantities that exceed the daily requirements of Canadian customers and firm export customers would actually be removed from Canada.

5.1.1.2 Conclusions

After giving consideration to the evidence, the Board estimates that the remaining established reserves available to Alberta and Southern are 7.6 EJ as of 31 December 1978.

Alberta and Southern has base requirements of approximately 5.7 EJ that are not fully dependent upon export approvals arising from these proceedings, and approximately 1.4 EJ of commitments that would occur if the requested export authorizations, including Pan-Alberta, are issued. The base requirements include pipeline fuel and Cochrane plant shrinkage totalling 10 percent of the throughput at Cochrane.

The Board's assessment of supply and demand of Alberta and Southern's system, presented in Table 5.1.1 and Figure 5.1.1, shows that a deficiency will occur in 1981, one year earlier than shown by Alberta and Southern. The Board's forecast includes a higher annual demand for A & S, arising from the Board's decision on the level of protection to accord existing export licences. Consequently, the Applicant's acknowledged inability to meet its projected lower level of demand is further aggravated, particularly its inability to meet its daily contractual obligation to Pan-Alberta of some 218 TJ (200 MMcf at 14.65 psia). The Board's forecast shows that a total of only 56.3 PJ would be available to Pan-Alberta over the period 1980 to 1982. To the extent that the cumulative averaging provisions are not exercised by Alberta and Southern to the maximum degree possible under its licences, the indicated deficiencies in deliverability would be reduced.

While Alberta and Southern has stated its intention to contract for the additional supplies necessary to make up the projected deficiencies, the Board observes that the quantity of some 1.6 EJ (1.4 Tcf), suggested by A & S to eliminate the shortfall, is relatively large.

Table 5.1.1.1

ALBERTA AND SOUTHERN

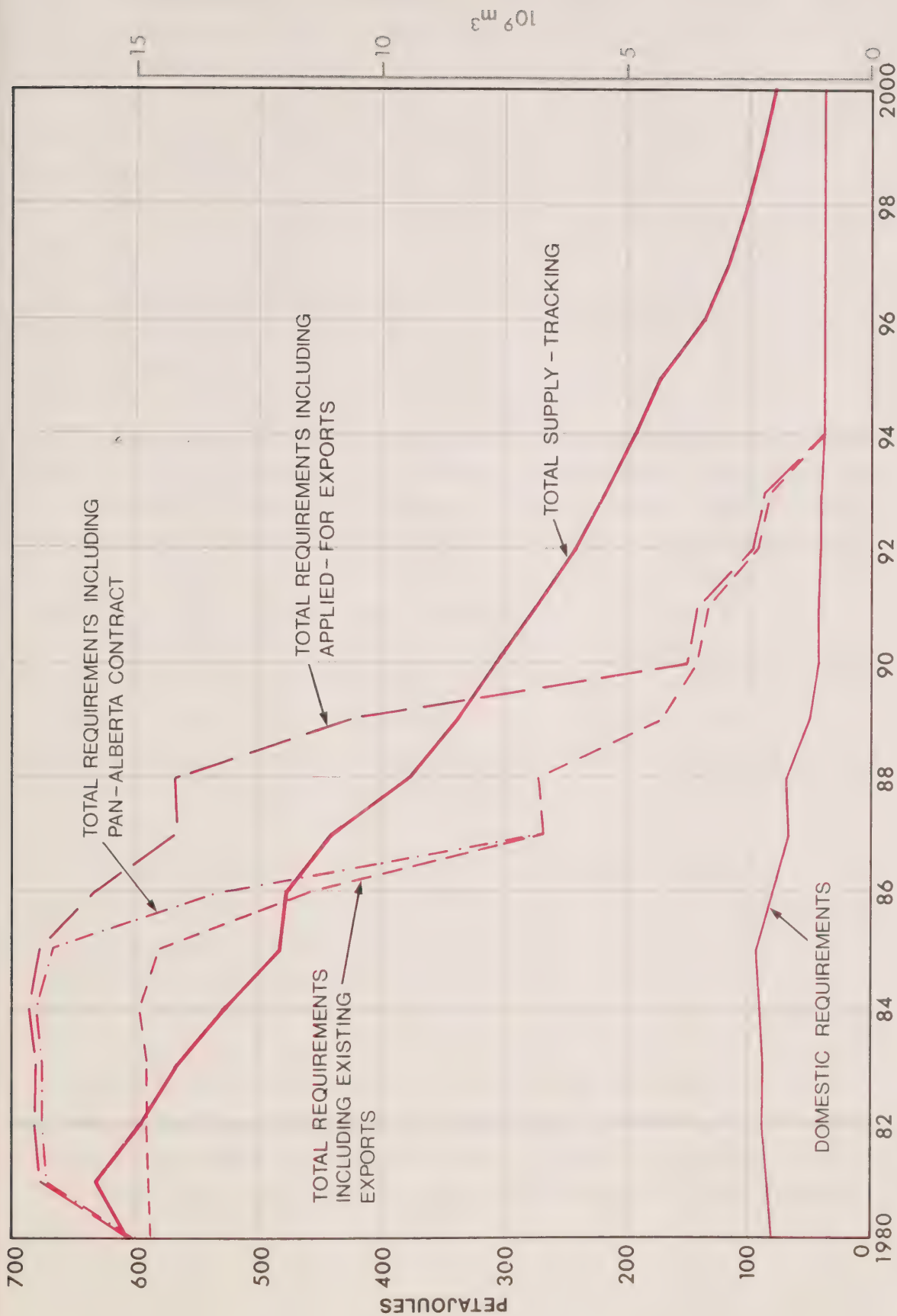
SUPPLY/DEMAND

YEAR	ALBERTA AND SOUTHERN FORECAST					NEB FORECAST	
	(As Filed)		(Converted by NEB)			Annual Demand	Annual Supply
	Annual Demand (10 ⁶ m ³)	Annual Supply (10 ⁶ m ³)	Annual Demand (PJ)	Annual Supply (PJ)			
1980	13 217	13 217	528	528	601.7	601.7	601.7
81	14 998	14 998	599	599	677.3	677.3	631.4
82	15 940	15 684	637	627	681.0	594.8	594.8
83	15 898	15 414	635	616	679.7	564.3	564.3
84	16 016	14 545	640	581	685.7	527.7	527.7
1985	16 071	14 680	642	586	677.8	482.4	482.4
86	15 311	13 531	612	541	632.3	477.5	477.5
87	13 624	12 632	544	505	564.1	441.6	441.6
88	13 686	11 620	547	464	567.2	375.9	375.9
89	11 767	10 688	470	427	424.6	336.8	336.8
1990	3 706	9 555	148	382	149.2	305.6	305.6
91	3 417	8 383	137	335	141.2	270.7	270.7
92	2 453	7 343	98	293	96.0	242.4	242.4
93	2 054	6 462	82	258	85.7	216.3	216.3
94	890	5 351	36	214	35.6	192.6	192.6
1995	893	4 643	36	185	35.7	170.5	170.5
96	895	4 099	36	164	35.8	134.9	134.9
97	898	3 609	36	144	36.0	114.8	114.8
98	901	3 245	36	130	36.1	99.7	99.7
99	904	3 062	36	122	36.2	87.0	87.0
2000	908	2 677	36	107	36.3	76.0	76.0

Source: (1) Exhibit 2-3, Tab 6.

(2) Exhibit 2-7, Tab 70, pg. 13

FIGURE 5.1.1



ALBERTA AND SOUTHERN
Annual Requirements vs. Supply

Although Alberta and Southern stated that the Future Deliverability Test only would apply to its application, the Board will consider the application under the Current Deliverability Test.

5.1.2 Facilities, Markets and Contracts

5.1.2.1 Evidence

Since the Alberta and Southern application involves only an extension to existing licences, existing gas movements would continue, and no additional facilities would be required.

A & S stated that if the licence extensions were granted, its current marketing arrangement would continue. Under that arrangement, A & S sells gas to PGT, which in turn sells the gas to PG & E for consumption in the California market. PG & E testified that it receives 17 percent of its gas supplies from California sources, 35 percent from the Permian, Anadarko, and San Juan Basins from El Paso, and the remaining 48 percent from Canada as purchases from A & S. PG & E also stated that it had recently contracted to purchase $6.4 \times 10^6 \text{ m}^3$ per day of Prudhoe Bay gas from Exxon Corporation with deliveries to begin in 1984-85. This delivery date and the associated volumes were not considered as firm due to the obstacles still facing the ANGTS.

Alberta and Southern's original gas sales contract with PGT is dated 31 January 1961. A supplemental agreement dated 5 April 1979 would allow PGT to purchase up to $5.8 \times 10^6 \text{ m}^3$ (205 MMcf) per day for the period 1 November 1985 to 31 October 1986 and $18.8 \times 10^6 \text{ m}^3$ (664 MMcf) per day from 1 November 1986 to 31 October 1989. The contract provides for take or pay penalties if less than 90 percent of the annual contract amount were taken.

The gas would be moved under existing transportation contracts between A & S and the two pipeline companies transporting its gas, AGTL and ANG.

5.1.2.1 Conclusions

The Board is satisfied that there are no impediments arising from facility, market, or contractual matters that affect the export application.

5.1.3 Other Matters

5.1.3.1 Evidence

Although Alberta and Southern was not required to submit a cost-benefit study, it did recommend in argument that the Board undertake a cost-benefit analysis of all of the export proposals, using a common set of assumptions. It stated that it had done some preliminary work on a cost-benefit

study and, based on that work, believed that a policy of approving exports associated with the Foothills prebuilt facilities and exports that would renew expiring licences would prove to be superior if analyzed within a cost-benefit framework. In particular, Alberta and Southern suggested that where the Board was faced with a choice between the renewal of an old licence and the granting of a new one, the Board should favour renewal. In its view, it would not be prudent to attach new customers to the ultimate detriment of existing customers. Alberta and Southern did not suggest a priority among existing licence holders. Instead, in the event of insufficient supply, Alberta and Southern suggested that the supply be shared in some way, and in a timeframe that would allow for sufficient planning.

5.1.3.2 Conclusions

The Board undertook a cost-benefit analysis of each of the applications. The Board estimates that the Alberta and Southern export proposal would result in net benefits to Canada of \$688 million (present value in 1978 dollars at a ten percent discount rate) based on the proposed export of $20\,679 \times 10^6 \text{ m}^3$.

5.2 Canadian-Montana

5.2.1 Supply, Deliverability and Requirements

5.2.1.1 Evidence

For the proposed export at Cardston, Canadian-Montana stated that it would rely on the supply evidence submitted by Alberta and Southern, as the gas would be purchased from A & S. Gas exported at the Cardston export point would be removed from Alberta under permits granted to Alberta and Southern, which expire in 1995.

With respect to the gas proposed for export at Aden, Canadian-Montana updated the detailed estimates of reserves contained in its submission to the 1978 Gas Inquiry. This summary of reserves indicated that as of 1 January 1979, 236.2 PJ (226.7 Bcf at 14.73 psia) of proved gas reserves remained in the Aden area fields. Canadian-Montana stated that it purchased Aden-area gas from its affiliate, Canadian-Montana Gas, under an amended contract for the period 21 September 1977 to 31 December 1992. The contract calls for maximum daily deliveries of 103.6 TJ (99.5 MMcf at 14.73 psia) and annual quantities of 20.727 PJ (19.9 Bcf). Canadian-Montana Gas produces approximately 70 percent of the gas in the Aden area and purchases the remaining 30 percent from other producers.

Canadian-Montana was granted AERCB Permit No. CM 76-3 on 16 February 1976 authorizing it to remove from certain fields in the Aden area a total of 570 PJ (550 Bcf at 14.65 psia) at a maximum daily rate of 103.6 TJ (100 MMcf at 14.65 psia) and an annual rate of 20.7 PJ (20 Bcf) during the term ending 31 December 1990. As of 1 January 1979, 167.9 PJ (162 Bcf) remained to be removed under the Permit.

In support of its application for a new licence to export at Aden, Canadian-Montana adopted its forecast of deliverability for the Aden supply area contained in its submission to the 1978 Gas Inquiry, stating there had been no material change in data or assumptions to affect the validity of its predictions. The study was based on maximum development and same appreciation of reserves. The forecast submitted utilized remaining marketable reserves of 265.2 PJ (254.5 Bcf at 14.73 psia) and showed that the applied-for annual quantities of 10.4 PJ (10 Bcf) could be met, except for a slight deficiency in the terminal year. The forecast is shown in Table 5.2.1. Canadian-Montana stated that a new licence for the Aden area reserves would enable it to develop these fields to their maximum potential.

Referring to Cardston exports, Canadian-Montana stated that it had a gas purchase contract with Alberta and Southern, which was on file with the Board. Evidence was adduced that the proposed Cardston restoration quantities required no change in the present contract. However, for the proposed licence extensions, Canadian-Montana had informed Alberta and Southern by letter of its intention to purchase additional A & S gas if the licences were granted. Canadian-Montana will continue to rely on its contractual agreements with Alberta and Southern to supply the additional quantities for Licences GL-5, GL-17, GL-25, and GL-36, and for the extension of GL-5 and GL-36.

With regard to requirements, Canadian-Montana stated that although it did not itself sell gas to customers in Canada, Canadian-Montana Gas makes retail sales to consumers in Manyberries, Alberta through the Chinook Gas Co-op, Ltd. and to certain farm tap customers in the very sparsely settled area of south-eastern Alberta. It also uses gas in its own operations. Gas is imported from Montana Power by Border Utilities Limited to serve the hamlet of Coutts, Alberta and by Canada Western Natural Gas Company, Ltd. to serve the village of Milk River, Alberta. No significant change in the gas market was anticipated for these areas. The retail sales of Canadian-Montana and Canadian-Montana Gas in

Canada were considered as domestic sales of Canadian-Montana. This market was forecast by Canadian-Montana to remain relatively constant until the year 2000, requiring an average annual quantity of 126.6 TJ (120 MMcf at 1000 Btu/cf).

At the end of 1978, Canadian-Montana had 265.1 PJ (244.3 Bcf at 14.73 psia) remaining under its existing licences. It had applied for new authorizations totalling 222.1 PJ (207.8 Bcf). Total potential exports are therefore 487.2 PJ (452.1 Bcf), including the 83.4 PJ (80 Bcf) under the requested new licence at Aden.

Alberta and Southern stated that the gas sales contract it had with Canadian-Montana had some 371.4 PJ ($9\,695.2 \times 10^6 \text{ m}^3$) remaining deliveries to the year 1993. Canadian-Montana recognized that the extension of its Cardston licences would be conditional upon there being sufficient gas deliverability developed to meet the indicated requirements. Exports at Cardston under existing licences and the proposed extensions could total some 403.2 PJ (372.1 Bcf at 14.73 psia).

Canadian-Montana stated that it adopted the Board's findings with respect to surplus as detailed in the 1979 Gas Report and that its proposed exports satisfied the Board's three surplus tests.

5.2.1.2 Conclusions

After giving consideration to the evidence, the Board estimates that the remaining established reserves controlled by Canadian-Montana in the Aden supply area are 304.6 PJ.

The Board is satisfied that Aden area reserves and the remaining quantity under AERCB Permit No. CM 76-3 exceed the quantity of the proposed new Aden licence. Furthermore the Board finds that deliverability from the Aden area is capable of meeting Canadian-Montana's requirements for the full term of the proposed exports, as shown in Table 5.2.1 and Figure 5.2.1. The table also indicates additional capability beyond the term requested and is presented as a maximum capability forecast thereafter.

The Board notes that the remaining contracted purchases from Alberta and Southern are not sufficient to serve both the exportable quantities under Canadian-Montana's four Cardston licences and the extensions requested. The indicated deficiency is 32.4 PJ. Canadian-Montana recognized the need to amend its supply contract with Alberta and Southern in order to obtain an additional 87.2 PJ (80.368 Bcf at 14.73 psia) of gas to meet the Cardston restoration

Table 5.2.1

CANADIAN-MONTANA - ADEN AREA

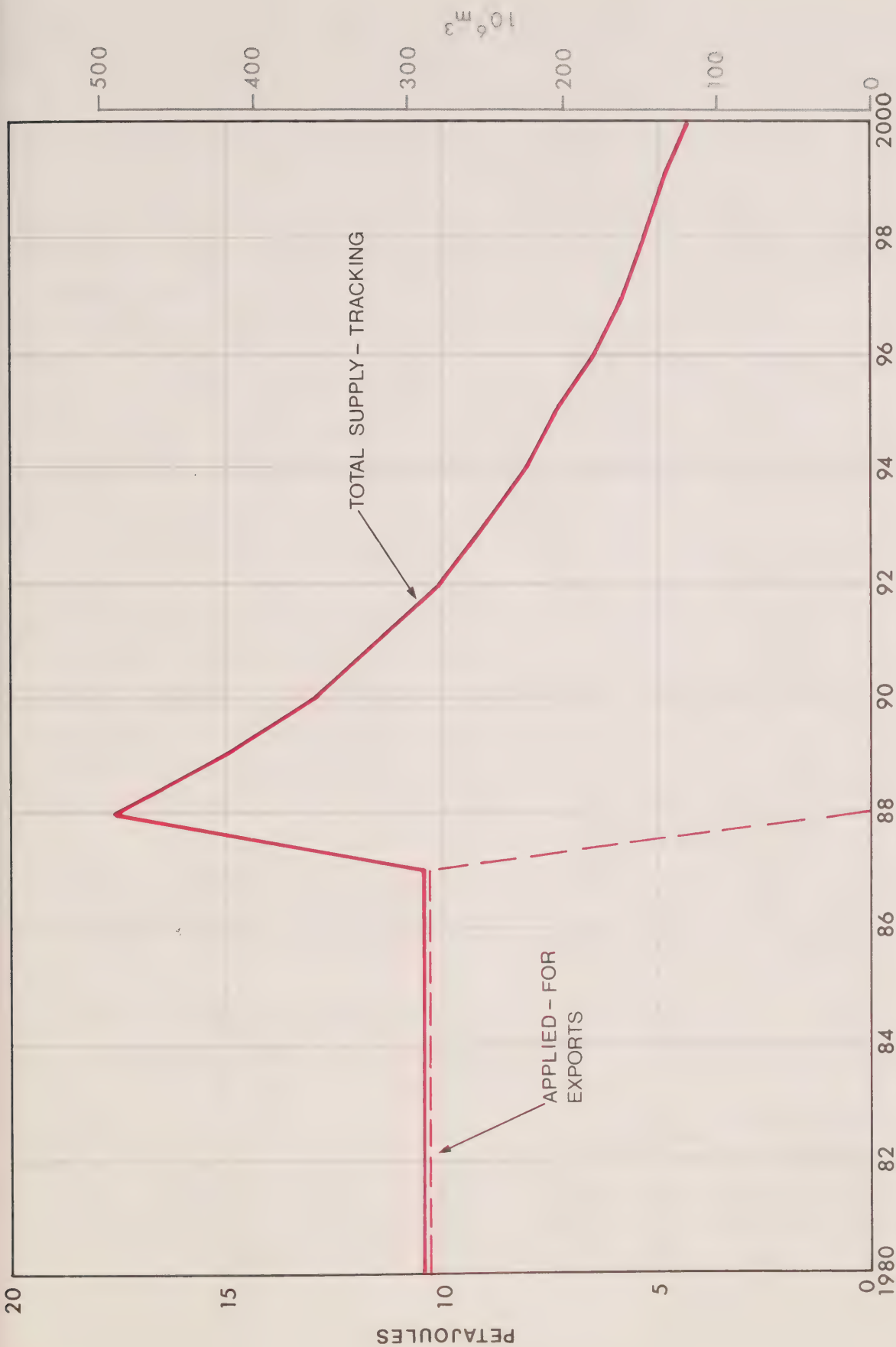
SUPPLY/DEMAND

YEAR	CANADIAN-MONTANA FORECAST						NEB FORECAST	
	(As Filed)		(Converted by NEB)				Annual Demand	Annual Supply
	Annual Demand	Annual Supply (2)	Annual Demand	Annual Supply				
	(Bcf)	(Bcf)	(PJ)	(PJ)			(PJ)	(PJ)
1980	10.0	16.1	10.4	16.8			10.4	10.4
81	10.0	16.7	10.4	17.4			10.4	10.4
82	10.0	16.0	10.4	16.6			10.4	10.4
83	10.0	15.2	10.4	15.8			10.4	10.4
84	10.0	14.4	10.4	15.0			10.4	10.4
1985	10.0	12.8	10.4	13.4			10.4	10.4
86	10.0	10.9	10.4	11.4			10.4	10.4
87	10.0	9.7	10.4	10.1			10.4	10.4
88		8.6		9.0				17.6
89		7.9		8.3				15.0
1990		7.3		7.6				13.0
91		6.7		7.0				11.5
92		6.2		6.4				10.1
93		5.7		5.9				9.0
94		5.2		5.5				8.1
1995		4.9		5.1				7.3
96		4.6		4.8				6.5
97		4.4		4.5				5.8
98		4.1		4.3				5.3
99		3.9		4.0				4.8
2000		3.6		3.7				4.3

(1) Exhibit 3-2, Tab 1, pg. 6 (at 14.73 psia and 60°F).

(2) Submission to GHR-1-78 (at 14.73 psia and 60°F).

CANADIAN - MONTANA
Annual Requirements vs. Supply



quantities. A letter of intent to this effect had been sent by Canadian-Montana to Alberta and Southern. The Board is not satisfied that Canadian-Montana would be able to readily obtain additional gas supplies from Alberta and Southern, in light of that Company's acknowledged deliverability deficiencies expected during the late 1980's.

5.2.2 Facilities, Markets and Contracts

5.2.2.1 Evidence

Canadian-Montana stated that as the exports at both Aden and Cardston would utilize existing facilities, no additional facilities would be required to transport its proposed new exports.

Canadian-Montana provided a description and forecast of Montana Power's market, which showed that Montana Power was dependent upon Canada for about 65 percent of its gas supplies. Information was provided on the reasons for the decline of total gas demand in Montana Power's market area since 1973, and measures were described whereby Montana Power had attempted to reduce dependency on Canadian supplies.

For the large part, existing sales contracts between Canadian-Montana and Montana Power would continue to be applicable to the proposed exports. However, a new contract dated 19 September 1977 was submitted, which provided for deliveries at the Aden point until the end of 1992. By virtue of this contract, Montana Power contracted to purchase up to $563.7 \times 10^6 \text{ m}^3$ (19.9 Bcf) per year at Aden, while indicating that it only intended to buy $283.3 \times 10^6 \text{ m}^3$ (10 Bcf) per year at Aden.

Canadian-Montana also had a contract to sell to TransCanada at Empress the difference between $872.2 \times 10^6 \text{ m}^3$ (29.2 Bcf) and the actual export levels at Cardston, but not exceeding $271.9 \times 10^6 \text{ m}^3$ (9.6 Bcf) per year.

5.2.2.2 Conclusions

The Board is satisfied that there are no impediments arising from facility, market, or contractual matters that affect the export application.

5.2.3 Other Matters

5.2.3.1 Evidence

Canadian-Montana provided a justification for the Cardston reinstatement quantities by submitting a tabulation of the total quantities of gas exported at Aden under the Cardston licences since the expiration of

Licence GL-8; these quantities were said to be some $2\,274.7 \times 10^6 \text{ m}^3$ (80.3 Bcf). Under cross-examination however, it was agreed that $566.5 \times 10^6 \text{ m}^3$ (20 Bcf) of the $2\,274.7 \times 10^6 \text{ m}^3$ (80.3 Bcf) was gas that could have been exported at Cardston but was instead exported at Aden, while only $1\,708.2 \times 10^6 \text{ m}^3$ (60.3 Bcf) was the quantity of accelerated exports provided by amendments to Canadian-Montana's licence following the expiry of Licence GL-8. (While the distinction is somewhat academic, the reinstatement of exported quantities should refer to accelerated exports only, as it is only the accelerated quantities that have been exported earlier than would otherwise have been the case.)

In its application, Canadian-Montana sought protection of its market which it claimed had been developed with, and was largely dependent upon, Canadian gas and was one that had no alternative source of gas supply within economic reach. It suggested that the spirit of international comity existing between Canada and the United States should be acknowledged, particularly when the quantities involved were relatively small.

During cross-examination, Canadian-Montana stated that licences serving existing markets dependent on Canadian gas should have first priority and that allocation between those existing licences should be on the basis of the quantity involved. If some surplus remained after satisfying existing licences, approval of the applications for new licences should be determined on the basis of the Canadian public interest. Canadian-Montana perceived its own applications to include an extension of an existing licence and an application to renew an old expired licence.

The cost-benefit study submitted by Canadian-Montana in response to the Board's request provided very limited information concerning the benefits and costs of the proposed additional exports. The study did not include an analysis of the costs and benefits that would result from the amendments to the Cardston licences.

The benefits were estimated to be the revenue derived from the export at Aden of only $1\,870 \times 10^6 \text{ m}^3$ (66 Bcf), based on a constant export border price of \$2.01 (U.S.)/GJ. In Canadian-Montana's view, there would be no cost to Canada in the production and transportation of the gas, except for the minimal amounts of fuel gas used to transport the gas to the border or to produce the gas. Moreover, it stated that there was no alternative local domestic market foreseen during the licence term.

The main results of the study were that exports would give benefits to Canada totalling \$143 million (U.S.) and, conversely, that Canada would incur a minimum loss of \$50 million if the gas were shut-in.

5.2.3.2 Conclusions

The Board concludes that the quantity of gas exported by Canadian-Montana under the various licence amendments made since the expiry of Licence GL-8, which permitted accelerated deliveries under Canadian-Montana's remaining licences, is $1\,708.2 \times 10^6 \text{ m}^3$ (60.3 Bcf).

The Board finds that the Canadian-Montana proposal for a new licence to export gas at Aden would result in net benefits to Canada of \$154 million, based on exports of $2\,266 \times 10^6 \text{ m}^3$ (80 Bcf). The net benefits from the Canadian-Montana proposal to reinstate quantities under GL-5, GL-17, GL-25, and GL-36 are estimated by the Board to be \$62 million, based on exports of $1\,708 \times 10^6 \text{ m}^3$ (60.3 Bcf). The net benefits from the proposed extensions of GL-5 and GL-36 are estimated to be \$49 million based on the proposed export of $1\,344 \times 10^6 \text{ m}^3$ (47.4 Bcf).

These Board estimates of the present value of the net benefits are in 1978 dollars at a ten percent discount rate.

5.3 Columbia Gas

5.3.1 Supply, Deliverability and Requirements

5.3.1.1 Evidence

Columbia Gas submitted detailed estimates of the reserves of the Kotaneelee Field, which indicated that remaining established reserves were 210 PJ (205 Bcf at 14.65 psia).

Columbia Gas stated that the gas purchase contract proposed to be entered into with the other producers of the Kotaneelee Field had not been executed pending execution of a processing and transportation agreement with Westcoast. The proposed contract stipulated a maximum daily delivery of 42.2 TJ (41 MMcf at 14.73 psia) and, annually, 14.0 PJ (13.6 Bcf).

In a letter dated 2 April 1978, the Assistant Deputy Minister of the Department of Indian and Northern Affairs stated that his Department had no objection to Columbia's gas export application, and that it was generally supportive of any measure that would result in continuous production from Kotaneelee.

Columbia Gas submitted a preliminary forecast of deliverability for the Kotaneelee Field (as shown on Table 5.3.1), which showed that with full development of six wells, the reserves of 210 PJ (205 Bcf at 14.65 psia) could maintain the applied for annual export quantity of 14.3 PJ (13.6 Bcf at 1000 Btu/cf) for a period of seven years.

Columbia Gas testified that the necessary facilities were in place, that the field could be on stream within 48 hours, and that, in fact, the field had produced 0.4 PJ (0.4 Bcf) of raw gas under a previous "best efforts" contract with Westcoast. Columbia added, however, that Westcoast would not guarantee the full maximum daily quantity of 42.2 TJ (41 MMcf at 14.73 psia) during the peak 60-day winter period until such time as its proposed mainline looping program was completed.

With respect to surplus determination, Columbia made reference to the 1979 Gas Report and to the Board's procedure used to determine gas surplus. Columbia stated that under the Current Reserves Test, the granting of its export application would still result in a surplus and would not create a deliverability deficiency from current reserves for a least five years. Columbia believed that the granting of its export application for fifteen years would not create a deficiency within the first ten years under the Future Deliverability Test. Columbia recommended that all of its gas be declared surplus since there is no Canadian market for gas from the Kotaneelee Field.

5.3.1.2 Conclusions

After giving consideration to the evidence, the Board estimates the remaining established reserves of the Kotaneelee Field to be 165 PJ.

The Board's assessment of Columbia's deliverability from existing established reserves (Table 5.3.1, Fig. 5.3.1) shows that the requested export quantities can be met in full for no longer than seven years, i.e., to 1986. Thereafter, deliverability would decline quite rapidly.

The Board's forecast compares favourably with that provided by Columbia. The main difference is in the flat life portion, where minor "deficiencies" result from slightly differing requirements. These arise from the Board's strict interpretation of the export quantities, as determined on a calorific basis.

With respect to Columbia's evidence on the applicability of the Board's three surplus tests to its proposed exports, the Board notes that it

Table 5.3.1

COLUMBIA - KOTANEELEE FIELD

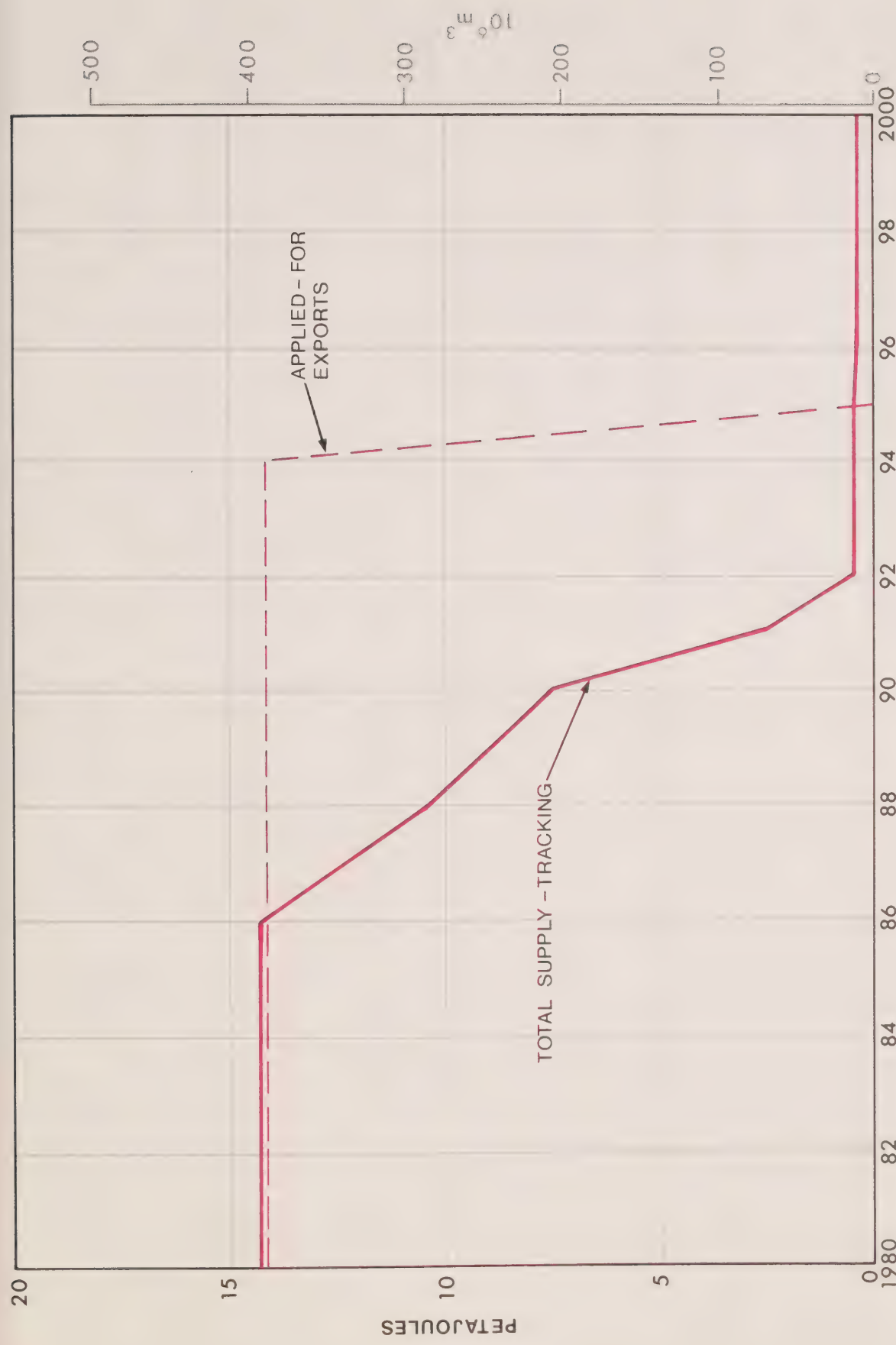
SUPPLY/DEMAND

YEAR	COLUMBIA FORECAST						NEB FORECAST	
	(As Filed)		(Converted by NEB)				Annual Demand (PJ)	Annual Supply (PJ)
	Annual Demand (1) (Bcf)	Annual Supply (2) (Bcf)	Annual Demand (PJ)	Annual Supply (PJ)	Annual Demand (PJ)	Annual Supply (PJ)		
1980	13.6	13.7	14.3	14.0	14.3	14.3	14.3	14.3
81	13.6	13.7	14.3	14.0	14.3	14.3	14.3	14.3
82	13.6	13.7	14.3	14.0	14.3	14.3	14.3	14.3
83	13.6	13.7	14.3	14.0	14.3	14.3	14.3	14.3
84	13.6	13.7	14.3	14.0	14.3	14.3	14.3	14.3
1985	13.6	13.7	14.3	14.0	14.3	14.3	14.3	14.3
86	13.6	13.7	14.3	14.0	14.3	14.3	14.3	14.3
87	13.6	11.3	14.3	11.7	14.3	14.3	12.4	12.4
88	13.6	8.9	14.3	9.1	14.3	14.3	10.4	10.4
89	13.6	7.0	14.3	7.2	14.3	14.3	8.9	8.9
1990	13.6	5.6	14.3	5.7	14.3	14.3	7.6	7.6
91	13.6	4.6	14.3	4.7	14.3	14.3	2.6	2.6
92	13.6	3.7	14.3	3.8	14.3	14.3	0.5	0.5
93	13.6	3.0	14.3	3.1	14.3	14.3	0.5	0.5
94	13.6	2.4	14.3	2.5	14.3	14.3	0.5	0.5
1995	2.0	2.0		2.1			0.5	0.5
96	1.6	1.6		1.6			0.4	0.4
97	1.4	1.4		1.4			0.4	0.4
98	1.0	1.0		1.0			0.4	0.4
99	0.8	0.8		0.8			0.4	0.4
2000								

Source: (1) Exhibit 4-2, Tab 1, pg. 3 (at 1000 Btu/cu. ft.)

(2) Exhibit 4-2, Tab 9 (at 14.65 psia and 60°F.)

FIGURE 5. 3.1



COLUMBIA
Annual Requirements vs. Supply

would be necessary for the full volume of a proposed export to meet the requirements of the three separate tests over the whole export period before the application could be granted in full.

5.3.2 Facilities, Markets and Contracts

5.3.2.1 Evidence

Columbia testified that as it had not yet concluded a transportation contract with Westcoast, it was not in a position to confirm definitively whether Westcoast could carry its gas without the construction of some additional facilities. However, it understood that Westcoast intended to apply to the Board for the construction of additional loops on its system, and that the transportation of the Columbia gas would be used by Westcoast as part of its justification for the looping program.⁽¹⁾

Columbia indicated that should additional facilities be required by Westcoast to transport its gas over the 15 years applied for, normal amortization would not recover the full facility costs. However, it felt that if the Kotaneelee field proved larger than the current estimate, there would be sufficient reserves to permit the recovery of all of the costs of the additional facilities.

Columbia Gas's U.S. customer is Columbia Transmission, a wholly-owned subsidiary of Columbia Systems. Columbia Transmission is a natural gas pipeline company engaged in the production, purchase, storage, transportation, and sale of natural gas to 75 affiliated and nonaffiliated distributors operating in Kentucky, Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia. The gas to be exported would be exchanged with that of El Paso, and the exchange quantity would form a part of the total pool supply of Columbia Transmission's entire system.

Columbia Transmission stated that it had not finalized transportation arrangements for its gas imports, but that it understood that some additional facilities would likely be required on the Northwest system.

Under the arrangements detailed in the application, the gas would be displaced by Northwest to El Paso at La Plata County, Colorado. The exchange quantity would be El Paso-owned production in the Gulf of Mexico delivered to

(1) See page 5-47 for further description of Westcoast's facilities requirements arising from the various export proposals.

Columbia Gulf Transmission Company ("Columbia Gulf") and hence to Columbia Transmission at Means and Leach, Kentucky. An alternative proposal would be that El Paso would deliver the gas by displacement to one of several pipelines, and the recipient would deliver the gas to Columbia Gulf or Columbia Transmission.

It was stated that the proposed exports represented less than one percent of Columbia Transmission's total supply. In addition, a witness for Columbia Gas testified that the cost of the proposed exchange arrangement would be in the range of $\$17.50/10^3 \text{ m}^3$ (\$.50/Mcf) to $\$35.00/10^3 \text{ m}^3$ (\$1.00/Mcf) resulting in a delivered cost similar to other sources of supply in the market area served by Columbia Transmission.

A witness for Columbia Gas testified that Columbia Transmission had yet to finalize arrangements with El Paso to complete the exchange arrangements in the United States, but indicated discussions were underway. Furthermore, contractual arrangements had not been completed with Northwest for the transportation of the gas to El Paso.

Columbia Gas filed a pro forma sales contract between Columbia Gas and Columbia Transmission approved for execution by both parties. Under the terms of the sales contract, Columbia Transmission was obligated to take delivery of up to $1\ 161 \times 10^3 \text{ m}^3$ (41 MMcf) per day, commencing 1 January 1980. On an annual basis, Columbia would be required to take or pay for $385 \times 10^6 \text{ m}^3$ (13.6 Bcf). The daily and annual quantities are identical to those applied for in the application.

With respect to processing, both the Kotaneelee dehydration plant and the Fort Nelson plant would be used to process gas from the Kotaneelee Field - the Kotaneelee plant would remove water vapour in order to meet the pipeline specifications of Westcoast, while the Fort Nelson plant would recover hydrogen sulphide through the sulphur recovery facilities of Westcoast. The processing plant in the Kotaneelee Field is operated on behalf of the partners on the basis of the actual costs and their working interests within the field.

Westcoast had given Columbia Gas an understanding that once the proposed processing and transmission agreement had been signed, it would give a waiver on the "best efforts" contract, under which some gas had been taken by Westcoast during early 1979. Processing costs were estimated to be $\$10.94/10^3 \text{ m}^3$ (31¢/Mcf), while the cost of service on Westcoast would be $\$20.23/10^3 \text{ m}^3$

(57.31¢/Mcf), based upon a daily throughput quantities of $1\ 161 \times 10^3 \text{ m}^3$ (41 MMcf) at 100 percent load factor. Columbia Gas hoped to conclude the processing and transportation agreement shortly after the close of the Hearing.

5.3.2.2 Conclusions

While satisfied that the gas can be marketed by Columbia Transmission, the Board notes that virtually no contractual arrangements have yet been finalized. However, the Board recognizes that under the special circumstances of the Columbia Gas application, finalization of the contractual arrangements should not be expected prior to a decision on the export application.

The Board does not believe that Columbia or Columbia Transmission would be able to conclude transportation agreements providing for the assured movement of the gas quantities unless additional facilities are installed on both the Westcoast and Northwest systems. The Board notes that there is a close relationship in this regard between Columbia's export application and that of Westcoast to increase the daily export quantity under Licence GL-41.

5.3.3 Other Matters

5.3.3.1 Evidence

Columbia Gas believed its application deserved priority consideration because it permitted gas to flow from the Yukon Territory, where Columbia's operations provided employment for native people.

During cross-examination, Columbia Gas stated that each application should stand on its own merits. It believed those applications that are deemed to be most in the public interest should be approved and that there should be no distinction drawn between a licence renewal and an application for a new licence. It did not support the concept of prorating any surplus available.

Although Columbia did not submit a cost-benefit analysis, it stated that without additional exports, exploration activity in Canada would drop substantially, perhaps by as much as 50 percent. Columbia stated that this was particularly applicable to the situation in the Yukon and the south-western portion of the Northwest Territories, where effectively all gas currently produced is for export.

5.3.3.2 Conclusions

In the Board's cost-benefit analysis of the Columbia export proposal, the Board found that the Columbia exports would result in net benefits to Canada of \$260 million (present value in 1978 dollars at a ten percent discount rate) based on the proposed export of $5\ 779 \times 10^6 \text{ m}^3$ (204 Bcf).

5.4 Niagara

5.4.1 Supply, Deliverability and Requirements

5.4.1.1 Evidence

Niagara stated that it purchased its principal gas supply from TransCanada under a gas sales contract dated 10 August 1962, which is to expire in 1987. Niagara and TransCanada had entered into an amending agreement dated 6 July 1979 that would provide Niagara with sufficient supplies to meet presently authorized exports and those applied for until 31 October 1995.

Niagara also had a gas purchase contract with Consumers' dated 31 October 1975 providing for the diversion to Niagara on an interruptible basis of contract-demand service gas that Consumers' buys from TransCanada.

Niagara's only requirements are its sales to St. Lawrence, which consist of remaining exportable quantities under Licence GL-6 of 48.5 PJ (45.2 Bcf at 14.73 psia) as of 31 December 1978 and the proposed new exports of 123.1 PJ ($3\,300 \times 10^6 \text{ m}^3$).

Niagara stated that the volume and quantities of gas applied for did not exceed the surplus remaining after due allowance had been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada.

Niagara added that it was applying for a 16-year firm export licence because of the uniqueness of the market in which the gas was to be consumed. Niagara pointed to the relatively small market to be served and to the fact that it was solely dependent on Canadian gas as no other source of gas supply was economically available. Niagara considered the export volumes applied for to be relatively small.

5.4.1.2 Conclusions

The quantities applied for by Niagara are included in the total TransCanada system requirements forecasts prepared by both TransCanada and the Board. Since the Board's supply-demand balance for the TransCanada system confirms TransCanada's evidence that no deficiencies will occur before 1985, Niagara's requirements are also assumed to be met until that time.

5.4.2 Facilities, Markets and Contracts

5.4.2.1 Evidence

The proposed new exports will be moved through the existing TransCanada and Niagara pipeline facilities. As the quantity is very small

compared with TransCanada's total system capacity, the exports would have a negligible influence on its system.

Niagara is the sole supplier of gas to its customer, St. Lawrence, which, like Niagara, is a wholly-owned subsidiary of Consumers'. Niagara submitted that as its export market had been developed with and was entirely dependent upon Canadian gas, it should be considered as a border accommodation.

Although St. Lawrence's market requirements had been met to date by gas exported under Licence GL-6 and other periodic short term exports, its market requirements had increased and would continue to do so. Furthermore, GL-6 would expire late in the 1984-85 licence year. This market growth was expected to reach an annual demand of $273.2 \times 10^6 \text{ m}^3$ by 1984 from the current level of $187.9 \times 10^6 \text{ m}^3$ and remain constant thereafter. Niagara explained that it was seeking the full growth increment of $85.3 \times 10^6 \text{ m}^3$ immediately to achieve operating and administrative flexibility.

Niagara's sales to St. Lawrence are made under a gas sales contract dated 2 January 1968. A Precedent Agreement dated 5 April 1979 provides for a continuation of sales through to 31 October 1995.

5.4.2.2 Conclusions

The Board is satisfied that there are no impediments arising from facility, market or contractual matters affecting the export application.

5.4.3 Other Matters

5.4.3.1 Evidence

Niagara suggested applications to export surplus Canadian gas should be categorized according to three types:

- (1) exports to markets that have been developed with and are entirely dependent upon Canadian gas, and that have no alternative source of gas within economic reach;
- (2) exports to markets that while now served by Canadian gas, are not entirely dependent on Canadian gas and do have an alternative source of gas supply; and
- (3) exports to new markets.

Niagara took the position that first priority should be given to category (1); if a surplus still existed, priority should be given to category (2) over category (3), assuming equivalent overall benefits to Canada from both. Competing applications in the same category should be judged on the basis of the overall Canadian public interest:

5.4.3.2 Conclusions

The Board's cost-benefit analysis of the proposed Niagara export of $3.2 \times 10^9 \text{ m}^3$ shows net benefits to Canada of \$114 million (present value in 1978 dollars at a ten percent discount rate).

5.5 ProGas

5.5.1 Supply, Deliverability and Requirements

5.5.1.1 Evidence

ProGas submitted detailed estimates of reserves under the lands for which it had gas purchase contracts. These estimates indicated that the remaining marketable gas reserves which ProGas had under contract totalled 2.57 EJ (2.36 Tcf at 14.65 psia), of which 1.81 EJ (1.66 Tcf) were proved and 0.77 EJ (0.70 Tcf) were probable.

ProGas had entered into long-term gas purchase contracts with producers, which provided for the purchase of gas for as long as ProGas was authorized to remove gas from Alberta. The purchase agreement was a reserve based type contract and called for a minimum daily quantity at a rate of take of 1:7300 with a maximum daily rate of 125 percent of the minimum daily quantity. The contract also obligated ProGas to take or pay for certain minimum annual quantities.

In its Report 79-D of July 1979, AERCB stated that it was prepared, subject to the approval of the Lieutenant Governor in Council, to grant a permit to ProGas authorizing the removal from Alberta of 1 287.3 PJ ($34.0 \times 10^9 \text{ m}^3$) of gas during the 15-year period commencing 1 November 1980 and terminating 31 October 1995. Maximum daily quantities would be 357.4 TJ ($9.44 \times 10^6 \text{ m}^3$) and the annual maximum would be 117.4 PJ ($3.1 \times 10^9 \text{ m}^3$). The authorized daily and annual quantities that AERCB had recommended matched the quantities ProGas was seeking for its first five years of export.

To demonstrate that it could meet its daily requirements of 357.4 TJ ($9.44 \times 10^6 \text{ m}^3$) for 20 years, ProGas submitted pool-by-pool forecasts of deliverability for two cases; one where a nominal amount of infill drilling had been included and the other, as shown in Table 5.5.1, with a somewhat higher degree of infill drilling. Deliverability was forecast using estimated established reserves of 2 188 PJ (2,008 Bcf at 14.65 psia), and rates of take were based upon negotiated contract quantities for each area.

Table 5.5.1

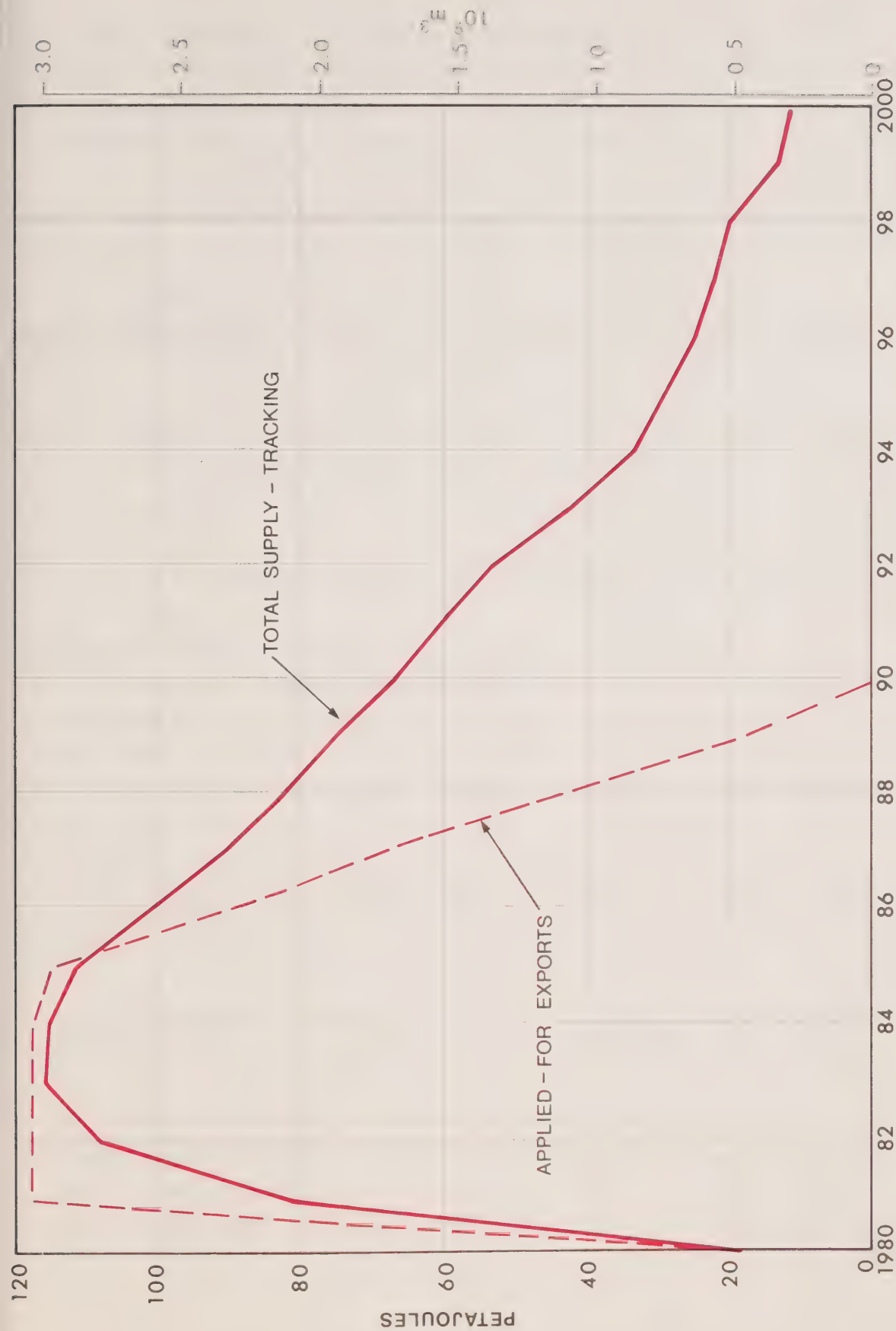
PROGAS

SUPPLY/DEMAND

YEAR	PROGAS FORECAST						NEB FORECAST	
	(As Filed)		(Converted by NEB)				Annual Demand (PJ)	Annual Supply (PJ)
	Annual Demand (1) (Bcf)	Annual Supply (2) (Bcf)	Annual Demand (PJ)	Annual Supply (PJ)	Annual Demand (PJ)	Annual Supply (PJ)		
1980								
81	110	91.1	117.3	96.1	117.4	92.2		
82	110	112.9	117.3	119.1	117.4	80.6		
83	110	112.9	117.3	119.1	117.4	108.2		
84	110	112.9	117.3	119.1	117.4	115.4		
					117.4	114.8		
1985	110	112.9	117.3	119.1	114.2	111.0		
86	110	112.9	117.3	119.1	89.6	100.9		
87	110	112.9	117.3	119.1	66.2	90.6		
88	110	112.9	117.3	119.1	43.7	82.4		
89	110	112.9	117.3	119.1	19.2	75.1		
1990	110	112.9	117.3	119.1				
91	110	112.9	117.3	119.1		67.1		
92	110	105.8	117.3	111.6		60.3		
93	110	98.8	117.3	104.2		53.7		
94	110	90.7	117.3	95.7		42.5		
						33.9		
1995	110	77.9	117.3	82.2				
96	110	65.8	117.3	69.4		29.2		
97	110	55.5	117.3	58.5		25.3		
98	110	43.9	117.3	46.3		22.7		
99	110	32.7	117.3	34.5		20.5		
						13.5		
2000	110	24.4	117.3	25.7				
						11.6		

Source: (1) Exhibit 10-2, Tab "Application" (at 14.65 psia and 60°F.)

(2) Exhibit 10-1, Tab "Summary", Table 2A (at 1000 Btu/cu. ft.)



PROGAS
Annual Requirements vs. Supply

On the assumption that exports would commence on 1 November 1980, ProGas indicated a build-up in maximum day deliverability to reach its full requirement level by the contract year 1981-82. Its forecast showed it could meet its requirements for ten years, with deliverability declining thereafter to the end of the 20-year term.

ProGas indicated that since many of the contracted lands were in early stages of development, it expected the reserves to appreciate, which would provide additional quantities of gas and assist in maintaining deliverability.

ProGas has executed contracts with its four United States customers and with TransCanada, which, in aggregate, provide for the sale of all of ProGas's contracted supply up to a maximum of 2.95 EJ (2.75 Tcf at 14.73 psia) over 25 years, or when ProGas's removal permit expires, whichever occurs first. If the maximum quantities were permitted by AERCB, ProGas would sell 817.8 PJ ($21.6 \times 10^9 \text{ m}^3$) to its U.S. customers and 2 131.6 PJ ($56.3 \times 10^9 \text{ m}^3$) to TransCanada.

ProGas's contractual arrangements provide for its supply and requirements to be in balance.

Regarding surplus determination, ProGas adopted the Board's findings contained in the 1979 Gas Report and applied these findings to its export application. ProGas demonstrated that the Current Reserves Test was satisfied. For the Current Deliverability Test, ProGas used the Board's total demand plus applied-for exports to show that deliverability from current reserves would be able to meet demand until 1985. ProGas noted that this projection was made as of 1 January 1979 and that it expected reserves additions since that date would extend the supply from current reserves. Under the Future Deliverability Test, ProGas used the supply equivalent to the Board's capacity forecast to show that the Future Deliverability Test was satisfied until 1992.

5.5.1.2 Conclusions

After giving consideration to the evidence, the Board estimates that remaining established reserves available to ProGas are 1.434 EJ.

In reviewing the reserves data submitted by ProGas, the Board concludes that many of ProGas's reserves evaluations involve potential reserves that will require additional drilling before being classified as established reserves by the Board. This provides the opportunity for substantial reserves appreciation in many pools.

The Board's assessment of ProGas's deliverability as presented in Table 5.5.1 and Figure 5.5.1 indicates that ProGas will not be capable of fully meeting its applied-for quantities in the first six years of its proposed exports. The Board recognizes that its assessment of deliverability is based upon a lower assessment of remaining established reserves than that of ProGas. Furthermore, the ProGas forecast of deliverability was based upon total proven plus probable reserves that greatly exceed the established reserves in certain fields.

5.5.2 Facilities, Markets and Contracts

5.5.2.1 Evidence

ProGas proposed that spare capacity in the TransCanada system be used to transport its gas, at least in the initial year of the export, and that this could be achieved by diverting to the Central Section of the TransCanada system gas destined for the Canadian market that would otherwise have been transported by Great Lakes. According to ProGas, the diversion would vacate sufficient capacity to permit the export of the quantities through Great Lakes without the addition of facilities on that system. ProGas testified that only minor facilities would have to be constructed in the Central Section of the TransCanada system at an estimated cost of \$27 million.

ProGas indicated that this proposal was based on the assumption that no exports would be approved other than TransCanada's proposed Licence GL-1 extension. It added that the approval of further exports to move by TransCanada would require the construction of new facilities. ProGas further testified that in each year after 1980, additional facilities would be required on the TransCanada system to accommodate growth in the Canadian market, and that these facilities would be constructed throughout the entire system. ProGas submitted evidence indicating that as exports decline, pipeline capacity would be vacated and could be utilized to transport gas for Canadian markets.

TransCanada indicated that the ProGas export proposal would cause the construction of some additional facilities on TCPL's Central Section earlier than would otherwise be the case, and that the cost of such facilities would be some \$230-240 million. However, TransCanada did acknowledge that these facilities would have been required eventually and would not be left vacant when the ProGas exports declined, since the projected rate of growth in the Canadian markets, which TransCanada believed to be conservative, would exceed the rate at which the proposed ProGas exports declined.

The ProGas quantities would be exported at Emerson, Manitoba for delivery to Great Lakes. At Great Lakes' Farwell compressor station, the gas would enter the facilities of Michigan Wisconsin for delivery, by exchange, to ProGas's other three United States purchasers - Natural Gas Pipe, Tennessee, and Texas Eastern.

ProGas's four United States customers all testified that the ProGas gas would be used to satisfy existing contract obligations and would therefore not be used to seek new market opportunities. The gas would be sold primarily in midwestern and eastern markets of the United States.

Michigan Wisconsin described its dependence on Canadian gas by pointing out that current annual imports of some $3\,399 \times 10^6 \text{ m}^3$ (120 Bcf) represented approximately 15 percent of Michigan Wisconsin's total annual supply. Although the ProGas quantity would represent only some three percent of Michigan Wisconsin's total annual supply of $21\,529 \times 10^6 \text{ m}^3$ (760 Bcf), it stated that it considered the quantity to be important. Michigan Wisconsin proposed to market the ProGas gas primarily in Michigan and Wisconsin.

Natural Gas Pipe indicated that its current five percent dependency on Canadian gas would increase as U.S. indigenous reserves began to decline and existing gas purchase contracts expired. The gas to be imported by Natural Gas Pipe would be sold in Texas, Oklahoma, Kansas, Nebraska, Iowa, Wisconsin, Illinois, Indiana, and Missouri. Natural Gas Pipe testified that the ProGas quantity represented approximately 2.5 percent of its total annual requirements.

Tennessee believed that curtailment of gas to its customers could resume as early as the forthcoming heating season. Its evidence included a forecast of the level of curtailed sales that Tennessee would face through to the 1997-98 heating season. Tennessee testified that the ProGas quantity would represent approximately two percent of Tennessee's total annual requirements.

Texas Eastern indicated that although it had made efforts to secure additional indigenous United States gas supplies to satisfy the growth in its annual requirements, it had not been able to do so. It was forecasting a supply shortfall, which would necessitate the curtailment of gas deliveries to its existing customers. The gas purchased from ProGas would help to limit the extent of this curtailment. The ProGas quantity represented approximately two per cent of Texas Eastern's total annual requirements.

Each of ProGas's four U.S. customers had contracted to take delivery starting 1 November 1980 of $2\,125 \times 10^3 \text{ m}^3$ (75 MMcf) per day for each of the first five years of the contract. The total daily quantity of $8\,500 \times 10^3 \text{ m}^3$ (300 Mcf) represented an average and was therefore lower than the licence maximum quantity of $9\,490 \times 10^3 \text{ m}^3$ (335 MMcf) per day requested in the application. The daily contract quantity would reduce by 20 percent in each of the sixth through to the tenth contract years. The contracts require the customers to take or pay for a minimum annual quantity equal to 85 percent of total annual maximum quantity. However, the minimum take-or-pay provision would be reduced by any deficiency occurring in pipeline capacity in Canada.

The gas sales agreement with TransCanada dated 16 March 1979 provided for the sale of the following daily contract quantities:

First five contract years	- 0 m^3	(0 MMcf)
Contract year 6	- $1\,700 \times 10^3 \text{ m}^3$	(60 MMcf)
Contract year 7	- $3\,400 \times 10^3 \text{ m}^3$	(120 MMcf)
Contract year 8	- $5\,100 \times 10^3 \text{ m}^3$	(180 MMcf)
Contract year 9	- $6\,800 \times 10^3 \text{ m}^3$	(240 MMcf)
Contract year 10 to expiration of permit, or to 31 October 2000, whichever occurs first.	- $8\,500 \times 10^3 \text{ m}^3$	(300 MMcf)

The contract would commence on the date ProGas's exports began. It contained a take-or-pay provision similar to that contained in the gas sales agreements with its United States customers.

The contract also provided that by giving 24 months notice, TransCanada could defer its right to purchase certain quantities of gas not required to serve its domestic market. ProGas's four United States purchasers would, subject to receiving all necessary regulatory approvals, be obligated under their gas sales agreements with ProGas to take delivery of the quantities so deferred by TransCanada. Should the United States purchasers or ProGas fail to obtain all necessary regulatory approvals for this export sale, the sales agreement with TransCanada required that TransCanada take delivery of the quantities previously deferred.

ProGas believed that this kind of marketing arrangement with TransCanada would ensure that adequate gas supplies would be available to satisfy any future growth in the Canadian market, while at the same time it allowed ProGas to develop and take advantage of export market opportunities on a short-term basis as they arose.

ProGas entered into a transportation contract with TransCanada dated 16 March 1979 under which TransCanada would be obligated to transport from Empress to Emerson a firm $8.5 \times 10^6 \text{ m}^3$ (300 MMcf) of gas per day, if it were tendered. The quantities would reduce in the sixth and subsequent years consistent with the sales contracts.

ProGas's four United States purchasers testified that although transportation contracts with Great Lakes had not been executed, no difficulties were foreseen in concluding such arrangements.

Natural Gas Pipe, Texas Eastern, and Tennessee indicated that negotiations with Michigan Wisconsin for the delivery of the gas to their respective pipeline systems were continuing.

5.5.2.2 Conclusions

Since the magnitude and the timing of the additional facilities required by TransCanada to carry both the ProGas exports and the proposed diverted quantities would depend not only upon the rate of growth of Eastern Canadian requirements but also upon the combination of such exports as may be approved, the Board has examined several alternatives, discussed in Chapter 7. The Board concludes, however, that the ProGas proposal would entail the construction by TransCanada of some \$200 million of additional facilities earlier than would otherwise occur. The Board believes that this could be a desirable result to the extent that additional facilities would be utilized to serve TCPL's system requirements as the exports decline and terminate. However, should such early construction of TCPL facilities result in any significant idling of capacity in future years, because other system requirements did not fill-in behind the proposed export quantities as they declined, then the Board might have concern that TransCanada's cost of service might be higher than necessary at that time.

The Board does not consider that there are any impediments to the proposed exports arising from markets or contractual matters.

5.5.3 Other Matters

5.5.3.1 Evidence

ProGas advocated the principle of deciding each application on its own merits. It suggested there were two broad categories of export applications - those that did not result in the sale of gas in the near future, and applications seeking more immediate sales in the U.S. markets. ProGas then suggested that licences that did not expire within the five-year term of the Current Deliverability Test should have lower priority than those seeking sales within the current deliverability period. Exports beyond that period, provided the Future Deliverability Test could be satisfied, should be granted on a conditional basis, if helpful to the initial sale of the gas.

ProGas provided a cost-benefit study that assessed the Canadian net economic benefit of the ProGas export proposal compared with an alternative case in which it was assumed that, if export sales were not made, sales of similar quantities would be delayed ten years and then sold in Canadian markets. In both cases the quantities would be transported on the AGTL and TCPL systems.

The benefits accruing from the exports were estimated to be the revenues derived from the sale of natural gas at a constant export border price of \$2.38/GJ.

The costs assessed in the study included the producers' costs, the transportation costs, and the opportunity cost of the natural gas that would be exported. The major assumptions used in estimating these costs were:

	<u>Per GJ</u>	<u>Per Mcf</u>
Production costs	\$0.38	\$0.40
AGTL cost of service	\$0.14	\$0.15
TCPL cost of service	\$0.23	\$0.25

In assessing the opportunity cost associated with the export quantities, the study estimated the gross benefits and costs attributable to the alternative future domestic sale of the gas, assuming the value of future domestic sales at Toronto of \$1.86/GJ. The opportunity cost of exporting the proposed quantities was represented as the difference between the gross benefits and costs resulting from this future alternative domestic use.

ProGas also identified several elements that it considered to be important in the overall assessment of its export project. These included a

strengthening in the value of the Canadian dollar; a more efficient utilization of the TCPL system in general; the putting in place of facilities that would eventually be required for use by the Canadian market and would be partially amortized during the period of United States sales; the creation of significant employment benefits; the maintenance of Canadian opportunities in the United States market that would be required for the marketing of frontier gas; and, to the extent that Canadian market expansion might be accomplished by providing some initial price incentives to the market-place, ProGas exports would provide an offsetting benefit to the potentially lower initial return that the gas producers and the Province of Alberta would otherwise receive.

The main result of the ProGas analysis was that a net gain of approximately \$790 million (present value in 1978 dollars based on a ten percent discount rate) in benefits would accrue to Canada from the proposed export sales of $21.7 \times 10^9 \text{ m}^3$ (767 Bcf). ProGas estimated this to be the net economic benefit that would accrue from current export sales as compared with the alternative of sales of equal quantities in the Canadian market ten years later.

ProGas also estimated that, at a discount rate of 15 percent, the present value of net benefits amounted to \$748 million.

With respect to the consideration in its cost-benefit analysis of the cost to Canadians of having to replace gas exported in the near future from conventional areas with possibly higher cost reserves or other sources of energy, ProGas stated that overly restrictive protection of Canadian markets resulting in large quantities of presently discovered natural gas being reserved for future needs would significantly reduce exploration and development activity. ProGas claimed that such a policy would be detrimental to the attainment of energy self-reliance in Canada. ProGas further stated that despite a current supply surplus, it was essential that exploration activity be continued at a high level in order to better evaluate the resource base and assure adequate supplies for future needs.

5.5.3.2 Conclusions

ProGas estimated the transmission companies' cost associated with the export volumes to be equal to the average cost of service tariff on the AGTL and TCPL systems. In the Board's view, it would be more appropriate to use an estimate of the incremental capital and operating costs that would exclude the financial and tax components incorporated in a pipeline tariff. It is noted

also, in calculating the benefits, that ProGas failed to include the value of by-products produced in association with the gas.

In assessing the alternative to exporting gas as proposed, ProGas assumed that gas production could be deferred for ten years and then used domestically at essentially the same rate. The Board notes that the effect of assuming that deliverability can be deferred and then be called upon for future Canadian use at the same rate as if the gas were to be produced now to serve the export requirements is to overstate the value of the alternative use and, as a result, under-estimate the net benefits of exporting gas.

In the view of the Board, the ProGas exports would result in net benefits to Canada of \$931 million (present value in 1978 dollars at a ten percent discount rate) based on the proposed export of $21.7 \times 10^9 \text{ m}^3$ (767 Bcf). The inclusion of the value of by-products associated with the gas produced and the use of a higher gas export price result in the Board's estimate of net benefits being higher than that of ProGas.

5.6 Sulpetro

5.6.1 Supply, Deliverability and Requirements

5.6.1.1 Evidence

Sulpetro submitted detailed estimates of reserves for those pools within Alberta for which it had gas purchase contracts. These estimates indicated that the remaining established gas reserves in such pools were 879 RJ (754 Bcf at 14.65 psia) of which 498 RJ (428 Bcf) had been contracted to Sulpetro.

Sulpetro stated that it was a working interest partner with others in the areas of Amisk, Chinchaga, Irish, Karr, and Valhalla, from which it proposed to export certain quantities of gas. It was adduced in evidence that Sulpetro had fully-executed gas purchase contracts with all the other interest owners except Mesa Petroleum, which had however signed a letter of intent. Gas purchase contracts would be offered to any new working interest owners.

Sulpetro has been granted AERCB Permit No. SC 78-1 dated 3 April 1979. The five gas fields referred to in Sulpetro's application, under Tab 3 (C), "Gas Purchase Contracts", correspond to nine pools, fields, and areas referred to in Permit No. SC 78-1. The term of the permit ends on 31 October 1981 and authorizes Sulpetro to remove 76.9 RJ ($2.030 \times 10^9 \text{ m}^3$) at a daily rate of 88.6 TJ ($2.34 \times 10^6 \text{ m}^3$) and 25.6 RJ ($0.676 \times 10^9 \text{ m}^3$) annually. Sulpetro has been granted an extension to 31 October 1982.

Sulpetro provided a "Production Forecast Summary" (as shown in Table 5.6.1) based on contracted reserves of 498.5 PJ (427.8 Bcf at 14.65 psia) showing, by area, the quantities contracted for removal from Alberta over the three-year period. The daily rate of 72.2 TJ (68.5 MMcf at 1000 Btu/cf) was the average production rate expected to be delivered over the 365-day period on a sustained basis to generate the 26.4 PJ (25 Bcf) annual quantity. The maximum daily rate stipulated in each gas purchase contract allowed for make-up due to plant turn-arounds and routine operating downtime or line outages. Sulpetro expected the Irish area to be developed sufficiently to provide for any unanticipated shortfall of delivery from the other contracted areas.

As all the fields would not be on stream in time, Sulpetro has made arrangements to purchase make-up quantities of gas on a "best efforts" basis from Pan-Alberta, to be made available under Pan-Alberta's AERCB Permit No. PA 74-1. The quantities to be purchased would decrease as Sulpetro's supplies came on stream. It anticipated requiring some 4.7 PJ (4.5 Bcf at 1000 Btu/cf) from Pan-Alberta for the 1979-80 winter season, although there was no commitment by Pan-Alberta for specific daily quantities.

In the event of a major disruption in production from its supply areas, Sulpetro indicated that Pan-Alberta had agreed to sell its excess deliverability, when requested to do so, to make up any supply deficiency. Sulpetro explained that Pan-Alberta would have the right to preempt all or part of the gas to be delivered to Transco commencing 1 November 1981. This, Sulpetro added, was consistent with its plan to have the end of its short-term export sale coincide with the commencement date of Pan-Alberta's deliveries through the prebuilt facilities of Foothills.

Sulpetro's only sales commitment is the proposed export sale of 69.6 PJ (66.0 Bcf at 1000 Btu/cf). After the termination of its export licence in 1982, Sulpetro's remaining gas reserves would be assigned to Pan-Alberta.

Sulpetro adopted the surplus findings contained in the Board's 1979 Gas Report. Sulpetro stated that under the Current Deliverability Test, the possible surplus shown in the Report was greatly in excess of annual quantities for which it applied. Sulpetro added that its proposed export would have a negligible effect on the current reserves surplus and on the protection of future deliverability.

5.6.1.2 Conclusions

After giving consideration to the evidence, the Board estimates the remaining established reserves available to Sulpetro to be 430.5 PJ. As shown by its assessment of Sulpetro's supply capability (Table 5.6.1 and Figure 5.6.1), the Board finds that Sulpetro is capable of meeting its export requirements for the three-year term as applied for. The Board's forecast beyond 1982 indicates additional capability, which peaks in 1983 at 26.8 PJ and gradually declines thereafter. This remaining capability would accrue to Pan-Alberta under existing contractual arrangements between the two companies.

5.6.2 Facilities, Markets and Contracts

5.6.2.1 Evidence

Sulpetro proposed to make use of spare capacity in the TCPL system to transport its gas to Eastern Canada for export. To be assured of deliveries on a year-round basis, a minor looping on the TCPL Niagara Section would be required, although evidence was given to reflect that this looping would be required by TransCanada regardless of the Sulpetro exports. As the Sulpetro exports are small compared with TCPL's total system capacity, their termination would have little effect on TCPL.

The proposed exports by Sulpetro would enter the United States at Niagara Falls, New York for delivery by exchange to Transco via the facilities owned and operated by Tennessee and by Consolidated Natural Gas Corporation. Transco operates an extensive pipeline system serving an area from Texas to the northeastern United States. While Transco had met with success in improving its domestic supply position, the Sulpetro quantities would enable it to reduce the current level of curtailment to its customers. Although the quantity of gas would constitute only some two to three percent of Transco's total supply, Transco considered this incremental supply to be significant.

A transportation contract had been signed with TransCanada dated 9 July 1979 under which TransCanada agreed to carry the Sulpetro gas. However, by a letter agreement of the same date, it was agreed that until TransCanada had installed additional capacity enabling it to provide firm service, TransCanada's transportation obligations would be limited to a "best-efforts" basis. Transco testified that transportation contracts had still to be formally executed with Tennessee and Consolidated Natural Gas Corporation; however, no difficulties were envisaged in this regard.

Table 5.6.1

SULPETRO

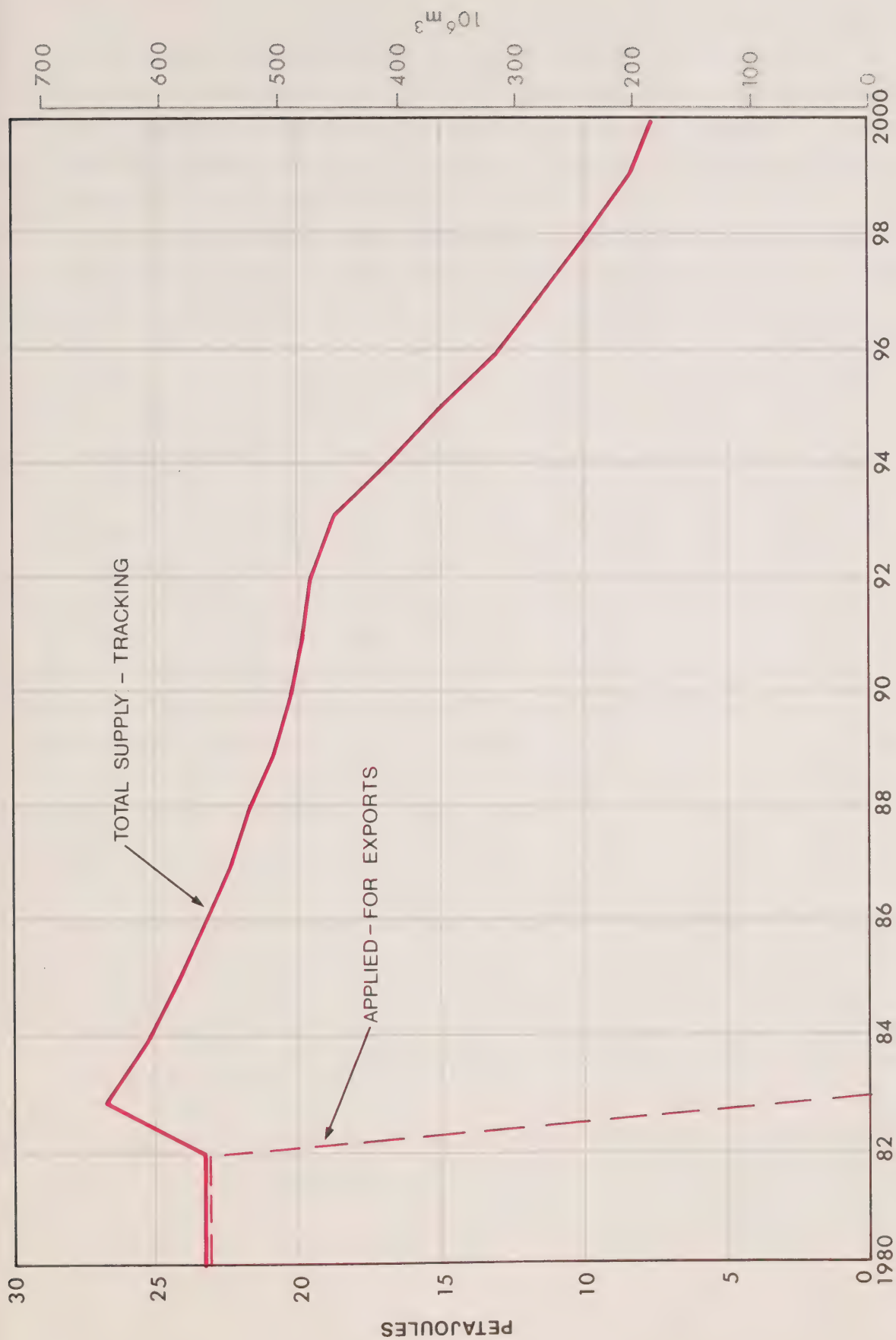
SUPPLY/DEMAND

YEAR	SULPETRO FORECAST				NEB FORECAST	
	(As Filed)		(Converted by NEB)		Annual Demand (PJ)	Annual Supply (PJ)
	Annual Demand (1) (Bcf)	Annual Supply (2) (Bcf)	Annual Demand (PJ)	Annual Supply (PJ)		
1980	22.0	25.0	23.2	26.4	23.2	23.2
81	22.0	25.0	23.2	26.4	23.2	23.2
82	22.0	25.0	23.2	26.4	23.2	23.2
83					26.8	
84					25.3	
1985						
86					24.2	
87					23.3	
88					22.4	
89					21.7	
1990					20.9	
91					20.3	
92					19.9	
93					19.6	
94					18.9	
1995					16.9	
96					14.9	
97					13.2	
98					11.4	
99					9.9	
					8.4	
2000					7.7	

Source: (1) Exhibit 11-9, Tab A, pg. 2 (at 1000 Btu/cu. ft.)

(2) Exhibit 11-13, Tab E (at 1000 Btu/cu. ft.)

FIGURE 5.6.1



SULPETRO
Annual Requirements vs. Supply

5.6.2.2 Conclusions

The Board is satisfied that there are no obstacles to the export by Sulpetro arising from market and contractual matters. Additional facilities are, however, required on the Niagara section of the TransCanada system. TransCanada has applied to the Board, outside of these proceedings, for approval to construct such facilities. Although the Sulpetro exports may be a factor in considering TransCanada's application, the Board notes that the full justification, including the long term need for such facilities, is a matter that will be subject to a separate hearing.

5.6.3 Other Matters

5.6.3.1 Evidence

It was Sulpetro's view that each application should be judged according to its merits. Sulpetro believed its licence ought to be granted because it would diminish the economic hardship to the natural gas producers, assist its United States customer to better meet the needs of its customers, permit the utilization of surplus pipeline capacity, and assist Sulpetro in maintaining investment in petroleum and natural gas exploration and development.

Sulpetro also suggested its application deserved priority because it involved a relatively small amount of gas over a short period of time. In that regard, it stated that the Board should seriously consider those applications that seek to renew licences close to termination and whose exports serve markets that are both small and geographically remote from alternative gas sources.

Sulpetro submitted a cost-benefit study providing an assessment of the costs and benefits to Canada of exporting the natural gas quantities proposed to be exported in Sulpetro's original (1978) application ($1.5 \times 10^9 \text{ m}^3$ or 52.6 Bcf). The study attempted to examine the net benefit of exporting the gas versus the alternative of retaining it for the domestic market, taking the difference to represent the incremental benefit or cost to Canada. In the alternative case, it was assumed that the gas would be sold domestically commencing in November 1984. In both cases, the proposed volumes would be transported on the AGTL and TCPL systems.

The benefits from exports were considered to be the total revenues received from the sale of the natural gas at the border based on a constant export price of \$2.24/GJ.

The costs examined in the study included the incremental capital costs to find, develop, and transport the gas to the export market as compared with retaining the gas for domestic use; the field and transmission operating costs associated with exporting the gas; and the cost to Canadians of replacing the proposed export with higher cost Arctic gas.

All capital costs associated with the export quantities were accumulated from April 1978. The study concluded that the magnitude of the total capital expenditures to find, develop, and transport the gas would be the same whether the gas was exported or retained for domestic use, although there would be some variance in the timing of the expenditures between the two cases.

Cost assumptions included:

	<u>Per GJ</u>	<u>Per Mcf</u>
Producers' operating costs	\$0.11	\$0.12
AGFL cost of service	\$0.13	\$0.135
TCPL cost of service	\$0.49	\$0.523

The study assumed that the proposed exports would have to be replaced by higher cost Arctic gas by about 1998. The present value of any incremental capital costs for Arctic gas development under the two alternatives, export versus no-export, would be negligible. As a result, the only incremental cost of significance would be that required for operating and transporting, estimated to be \$0.28/GJ.

It was noted in the study that no attempt was made to quantify benefits in the areas of job creation, stimulation of exploration, the national trade balance, or the multiplier effect of the additional money input into the Canadian economy. However, Sulpetro expressed the view that the proposed gas export would also provide additional benefits to Canadians in these areas.

The major result of the Sulpetro analysis was that net benefits of approximately \$57.2 million (present value in 1978 dollars based on a ten percent discount rate) would accrue to Canada based on exports of $1.5 \times 10^9 \text{ m}^3$ (52.6 Bcf).

Sulpetro subjected these results to a sensitivity analysis with respect to discount rates at 5 and 15 percent. The present value of net benefits ranged from \$63.5 million to \$50.7 million respectively.

5.6.3.2 Conclusions

The Board notes that while Sulpetro's study assessed the incremental capital costs in both the export case and in the alternative case (where the gas is used in Canada), it did not assess the operating costs for either case or the benefits associated with the alternative.

The Board also finds that rather than estimating transmission company costs on the basis of the average cost of service tariff on the AGTL and TCPL system, it would be more appropriate to use a more detailed estimate of the incremental capital and operating costs associated with the export quantities.

In the Board's view, Sulpetro's export proposal would result in net benefits to Canada of \$129 million (present value in 1978 dollars at a ten percent discount rate) based on Sulpetro's amended application to export $1\,870 \times 10^6 \text{ m}^3$ (66 Bcf). The Board's inclusion of the value of gas by-products, its use of a higher gas export price, and the larger volume as proposed in the amended application, results in net benefits being higher than those shown by Sulpetro.

5.7 Westcoast

5.7.1 Supply, Deliverability and Requirements

5.7.1.1 Evidence

Westcoast submitted detailed estimates of the reserves located in those pools that support the existing Licence GL-4 and that are removed from Alberta under AERCB Permit No. WC 59-3. These estimates indicated that of the total 451.7 PJ ($11.965 \times 10^9 \text{ m}^3$) remaining pipeline gas reserves, 343.3 PJ ($9.094 \times 10^9 \text{ m}^3$) were controlled by Westcoast.

To support its application for an extension to Licence GL-4, Westcoast submitted an amended deliverability forecast (Table 5.7.1A) for its controlled remaining reserves from southern Alberta fields named in AERCB Permit No. WC 59-3. Also included was the anticipated delivery of contracted Pan-Alberta quantities authorized for removal from Alberta under AERCB Permit No. PA 74-1. The annual forecast from the controlled reserves under Permit No. WC 59-3 indicated a decline from 49.8 PJ ($1\,319 \times 10^6 \text{ m}^3$) in 1980 to 4.1 PJ ($108 \times 10^6 \text{ m}^3$) by 1987. Since Westcoast is authorized to export 56.0 PJ (51 Bcf at 14.73 psia) under Licence GL-4, it is deficient from 1980 onwards.

From 1981 to 1988, the deliverability from Westcoast's controlled reserves was supplemented by gas contracted from Pan-Alberta to maintain total annual quantities of some 43 PJ ($1\,133 \times 10^6 \text{ m}^3$) until 1989.

With respect to Licence GL-41, Westcoast submitted a pool-by-pool summary of the reserves contained in its supply area of Northeastern British Columbia, portions of the southern Yukon and the Northwest Territories, and the fields in Northwestern Alberta named in AERCB Permits Nos. WC 52-1, WC 61-4, and WC 62-5. Westcoast estimated that there were 8.66 EJ ($222.3 \times 10^9 \text{ m}^3$) of pipeline gas remaining in these pools as of 1 January 1979, of which 6.85 EJ ($175.9 \times 10^9 \text{ m}^3$) were controlled by Westcoast. These estimates include 101.6 PJ ($2.8 \times 10^9 \text{ m}^3$) remaining reserves in the Kotaneelee Field. In supplementary evidence, Westcoast reduced these reserves estimates by about 15.6 PJ ($400 \times 10^6 \text{ m}^3$). Since detailed reservoir data as of 1 January 1978 for all pools supplying the main Westcoast system were filed with the Board as part of the recently-heard Junior-Sierra pipeline application, Westcoast supported its export application with detailed reservoir data for only 12 fields, but together they accounted for 80 percent of the total changes to reserves that occurred during 1978.

Westcoast also provided a supply forecast covering proved remaining reserves under its control in its supply areas in British Columbia, Northwest Alberta, and the Northwest Territories, as well as for contracted gas supply available from Pan-Alberta after allocation of the quantities to maintain Licence GL-4. This forecast, in support of its application to maintain exports under Licence GL-41, was based in part on the remaining reserves of 6.74 EJ ($173.1 \times 10^9 \text{ m}^3$) as of 1 January 1979. The forecast did not include deliverability from the Kotaneelee Field in the Yukon or Alberta quantities after 1989. Westcoast's total supply forecast, including trend gas, is shown in Table 5.7.1.B. It demonstrated that on this basis, it could meet its total requirements through 1997.

Westcoast provided detailed estimates of domestic requirements for the period 1979 to 1997. Westcoast's total Canadian market requirements to the end of 1995, including pipeline fuel, shrinkage, and interruptible industrial sales, were given as 4.4 EJ ($113.5 \times 10^9 \text{ m}^3$).

The remaining potential exports under Licence GL-41 as of 1 January 1979 were estimated in the 1979 Gas Report to be 3.1 EJ (3.4 Tcf). Due to

licence restrictions, Westcoast estimated that by 31 October 1989, when the licence would expire, some $13\,908 \times 10^6 \text{ m}^3$ would remain unexported. The proposed extension to Licence GL-41 from 1989 to 1995 would add an additional $18.4 \times 10^9 \text{ m}^3$. In total, Westcoast indicated that potential export requirements under Licence GL-41 from 1 January 1979 to 31 October 1995 would be some $113.4 \times 10^9 \text{ m}^3$, assuming full quantities were taken on the current licence, all applied for quantities were approved, and the indicated unexported quantities remaining in 1989 were also exported.

Westcoast stated that it accepted the Board's three surplus tests as set out in the 1979 Gas Report and that its application satisfied these three tests.

5.7.1.2 Conclusions

The Board has reviewed Westcoast's remaining reserves under AERCB Permit No. WC 59-3 and concludes that some 352.3 PJ are available for export under Licence GL-4.

For purposes of its own forecast, which is shown on Table 5.7.1.A and Figure 5.7.1A, the Board has assumed that Westcoast's requirements vis-a-vis Licence GL-4 are the licensed annual quantities of 56 PJ (51 Bcf). The Board's forecast of supply for Licence GL-4 includes Westcoast's estimate of its share of production from the Crossfield Field and the Board's forecast for the Irricana and Savanna Creek Fields. This forecast was supplemented by allocating sufficient gas from the annual contract quantities available from Pan-Alberta. The Board's forecast shows that Westcoast could meet the full requirements of the applied-for licence extension until 1985. After 1985, there would be insufficient quantities available from Pan-Alberta and from the designated Westcoast fields to meet maximum potential exports for the remainder of the term.

After giving consideration to the evidence with respect to Westcoast's Licence GL-41, the Board estimates the remaining established reserves available to Westcoast to satisfy its British Columbia domestic demand and the proposed export under Licence GL-41 to be 8.1 EJ as of 1 January 1979, of which 0.2 EJ are considered beyond economic reach. This total excludes the reserves of the Kotaneelee Field.

The Board's forecast of deliverability available to Westcoast to meet its main system requirements, shown in Table 5.7.1.B and Figure 5.7.1B, shows deficiencies commencing in 1983. The Board's forecast of supply

Table 5.7.1 A

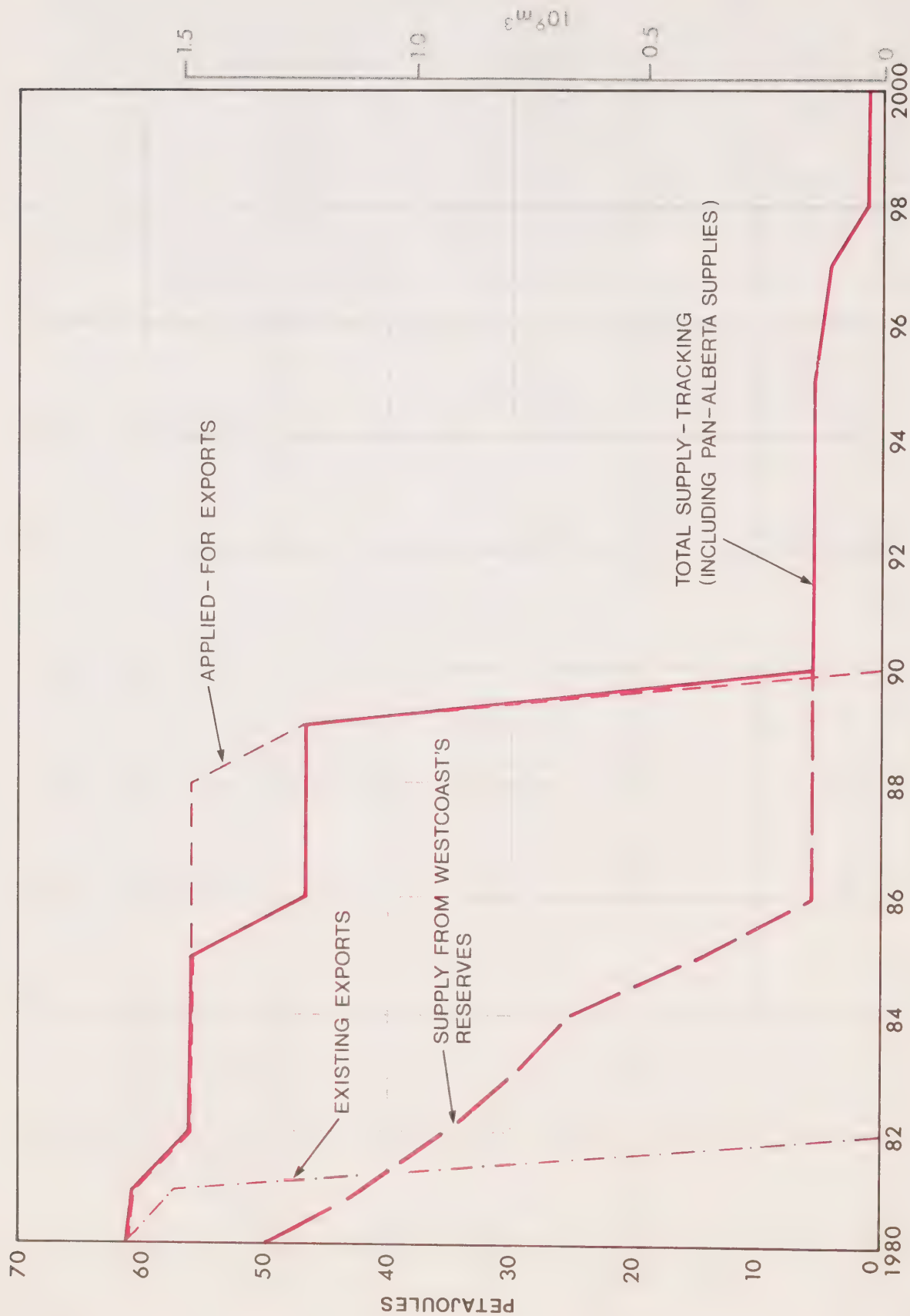
WESTCOAST - GL-4

SUPPLY/DEMAND

YEAR	WESTCOAST FORECAST						NEB FORECAST	
	(As Filed)		(Converted by NEB)				Annual	Annual
	Annual Demand	Annual Supply	Annual Demand	Annual Supply	Annual Demand	Annual Supply	Demand	Supply
	(10 ⁶ m)	(10 ⁶ m)	(10 ⁶ m)	(10 ⁶ m)	(PJ)	(PJ)	(PJ)	(PJ)
1980	1 445	1 319			56	49.8	61.1	61.1
81	1 445	1 133			56	42.8	60.8	60.8
82	1 445	1 133			56	42.9	56.0	56.0
83	1 445	1 133			56	42.9	56.0	56.1
84	1 445	1 133			56	43.0	56.0	56.0
1985	1 445	1 133			56	43.3	56.0	55.9
86	1 445	1 133			56	43.4	56.0	46.7
87	1 445	1 133			56	43.4	56.0	46.6
88	1 445	1 133			56	43.4	56.0	46.6
89	1 445	910			56	34.9	46.6	46.6
1990								5.2
91								5.2
92								5.1
93								5.1
94								5.1
1995								5.0
96								4.6
97								3.9
98								0.9
99								0.9
2000								0.9

Source: (1) Exhibit 13-2, Tab "Application".

(2) Exhibit 13-18



WESTCOAST LICENCE GL-4
Annual Requirements vs. Supply

Table 5.7.1 B

WESTCOAST - GL-41

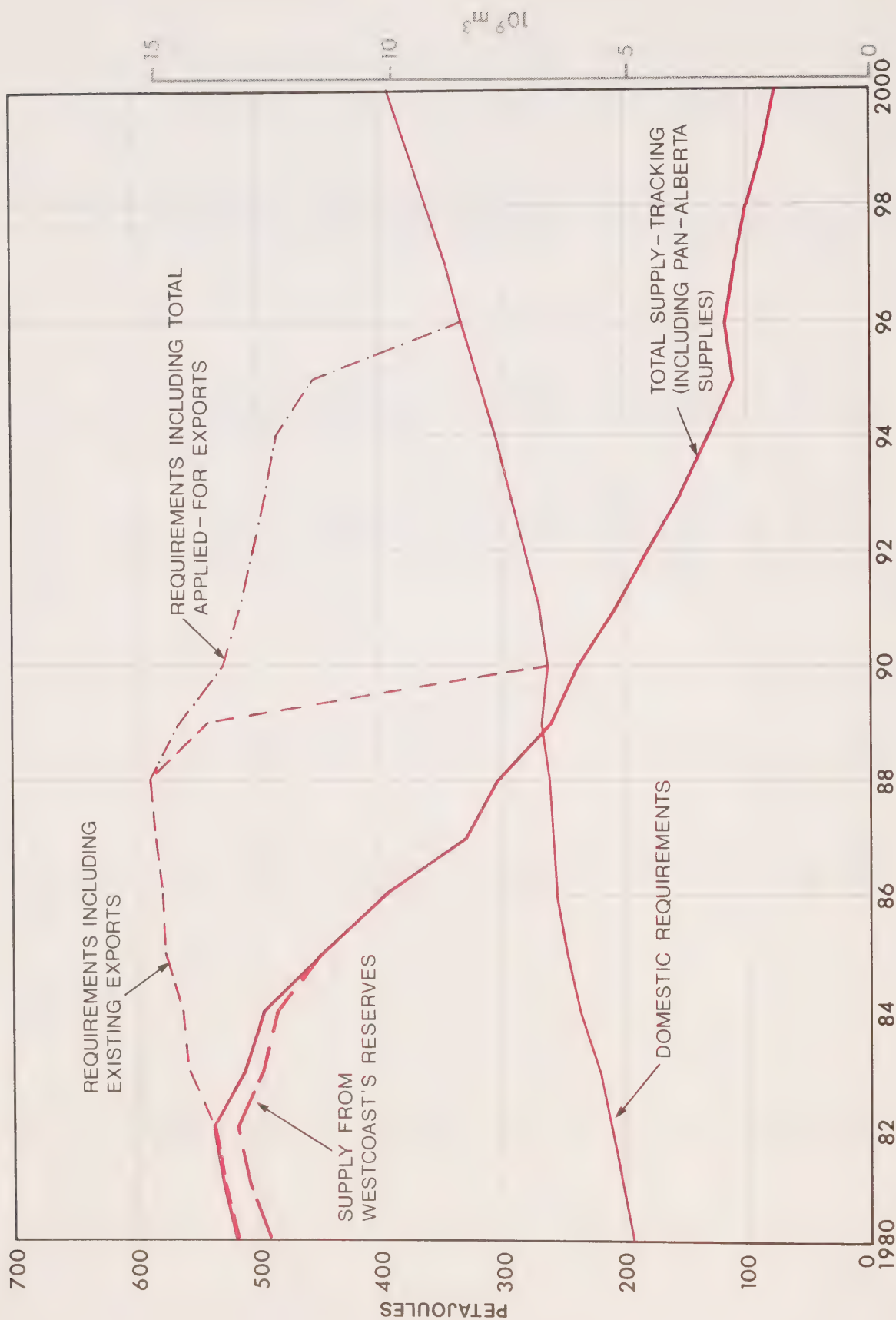
SUPPLY/DEMAND

YEAR	WESTCOAST FORECAST					NEB FORECAST (3)	
	(As Filed)		(Converted by NEB)			Annual Demand	Annual Supply
	Annual Demand	Annual Supply	Annual	Demand	Annual Supply		
	(10 ⁹ m ³)	(10 ⁹ m ³)	(10 ⁹ m ³)	(PJ)	(PJ)	(PJ)	(PJ)
1980	12.3	12.3	479.0	479.0	479.0	518.1	518.1
81	12.5	12.5	486.8	486.8	486.8	526.1	526.1
82	12.6	12.6	490.7	490.7	490.7	534.5	534.5
83	13.3	13.3	517.9	517.9	517.9	555.4	508.5
84	13.6	13.6	529.6	529.6	529.6	560.2	493.6
1985	13.8	13.8	537.4	537.4	537.4	572.6	444.0
86	14.1	14.1	549.1	549.1	549.1	577.8	393.0
87	14.3	14.3	556.9	556.9	556.9	581.0	326.7
88	14.6	14.6	586.5	586.5	586.5	586.2	299.5
89	14.8	14.8	576.3	576.3	576.3	562.7	258.2
1990	14.0	14.0	545.2	545.2	545.2	525.9	233.6
91	13.7	13.7	533.5	533.5	533.5	511.3	205.6
92	13.3	13.3	517.9	517.9	517.9	500.8	178.6
93	13.2	13.2	514.0	514.0	514.0	491.5	150.0
94	12.8	12.8	498.5	498.5	498.5	481.0	129.4
1995	12.1	12.1	471.2	471.2	471.2	449.6	106.9
96	9.0	9.0	350.5	350.5	350.5	329.0	113.6
97	9.2	9.2	358.3	358.3	358.3	343.8	106.5
98		12.1			471.2	358.6	97.1
99						375.0	85.0
2000						392.0	74.1

Source: (1) Exhibit 13-18

(2) Exhibit 13-18 (includes trend gas commencing in 1983)

(3) Without trend gas.



WESTCOAST LICENCE GL-41
Annual Requirements vs. Supply

available to serve the main system includes supply available from Pan-Alberta under its AERCB Permit No. PA 74-1, less those quantities required to supplement the Licence GL-4 requirements from that Permit. The Board's forecast excludes supply after 1989 from Alberta fields now contributing to Westcoast's supply under AERCB Permit Nos. WC 52-1, WC 61-4, and WC 62-5, because Westcoast stated that it does not intend to renew or extend those Permits beyond 1989. It should be noted that Westcoast's forecast includes deliverability from trend gas, whereas the Board's forecast does not.

The Board recognizes that the deficiencies shown arise partially from the treatment given to existing licences, whereby the Board has assumed that Licence GL-41 exports will be taken in full. Therefore, to the extent that Westcoast does not exercise its make-up provisions under Licence GL-41, the year when a deficiency first occurs might be delayed.

5.7.2 Facilities, Markets and Contracts

5.7.2.1 Evidence

Westcoast testified that no new facilities would be required to transport gas proposed to be exported under its application to extend Licence GL-4. However, Westcoast noted that it did not have adequate system capacity to meet its current peak day domestic requirements and export obligations under Licence GL-41. Thus, on peak days it would not be able to deliver either the additional gas to meet the increase in the maximum daily volumes under Licence GL-41 or be able to carry the proposed Columbia exports.

Westcoast stated that if the increase in Licence GL-41's maximum daily quantity and the Columbia export were approved, it would seek to obtain Board approval of the looping program it had applied for earlier, the application for which had been adjourned sine die by the Board on 29 May 1979. In its February 1979 application for a Certificate of Public Convenience and Necessity, Westcoast proposed to construct 86.5 km (54 miles) of 900-mm (36-inch) pipeline looping in nine sections of its British Columbia mainline, at a total cost of \$42.2 million. Westcoast later applied for and received approval to construct 8.8 km (5.5 miles) of pipeline loop in the Summit Lake area, costing \$4.8 million.

Gas exported under Licence GL-4 is sold by Northwest primarily in the Spokane and eastern Washington State area. Westcoast advised that Northwest would have to make fairly extensive changes to its system flow if Licence GL-4

were not extended, and Northwest's capability to continue to make off-line sales of GL-41 quantities would be affected. Northwest has taken gas under Licence GL-4 at an average load factor of 90 to 95 percent during the past ten years.

With respect to the market area served by exports under Licence GL-41, evidence indicated that some 60 percent of the gas requirements of western Washington and Oregon were met from such gas. During the past several years, however, Northwest has had difficulty marketing Canadian gas, which has been price sensitive in the face of competition from low-priced hydro-electricity and residual fuel oil. As a result, Westcoast's deliveries to Northwest have been well below contracted and licensed levels. Westcoast testified that a number of developments should relieve this situation. Northwest has made certain short-term off-line sales to other transmission companies, and the proposed sale to El Paso of incremental quantities plus interruptible or "best efforts" gas would help to increase delivery levels. In addition, prices of competing oil products have risen dramatically during 1979, improving the competitive position of Canadian gas in this market. Westcoast expected 1979 export sales to reach an 80 percent load factor.

The proposed sale to El Paso would require the installation of some \$55 million of additional facilities on the Northwest system between Portland and Stansfield, Oregon to permit the assured transmission of the gas. Once those facilities are in place, gas would be delivered to El Paso at Ignacio, on the border between Colorado and New Mexico, by displacement on the Northwest System. In order for the cost of the facilities to be recovered, and in order for United States authorities to approve the import of the gas, El Paso stated that the sale would have to be for at least nine years, but preferably for twelve.

Westcoast stated that the 23 September 1960 gas sales agreement covering the Licence GL-4 export at Kingsgate had been amended on 6 July 1979 to extend the primary term to 1 November 1989. With respect to Licence GL-41, Westcoast testified that the Fourth Service Agreement with Northwest, dated 10 October 1969, had not been amended to extend its term to 31 October 1995. While negotiations had been going on, they had not been able to reach agreement on the question of the minimum annual load factor. Although the original contract had included a minimum annual bill provision equivalent to a take-or-pay of 86.25 percent of contract quantities, this provision became ineffective with increases in the export price.

Westcoast felt that the proposed sale of firm and interruptible quantities to El Paso would help to resolve the load factor problem under Licence GL-41. El Paso had signed a contract for a 12-year term, but discussions with Northwest were required before Westcoast could sign it. The contract provided for a firm delivery of $1.7 \times 10^6 \text{ m}^3$ (60 MMcf) per day at a 100 percent load factor, plus $1.4 \times 10^6 \text{ m}^3$ (50 MMcf) per day of best efforts gas. The "best efforts" gas would be gas available to but not taken by Northwest, and would come from the daily contract quantity of $22.9 \times 10^6 \text{ m}^3$ (809.2 MMcf) provided for under the Fourth Service Agreement. With respect to gas supply for Licence GL-41, Westcoast testified that its contract with BCPC would require amendment to provide for both the incremental daily quantities and for the extensions. A letter of intent had been received from BCPC which indicated BCPC would supply the additional gas, subject to certain conditions.

British Columbia had stated that the extension of Licence GL-41 was not acceptable in the absence of a significantly higher annual load factor. However in light of the El Paso sale, it was able to support the amendments to Licence GL-41 as they would give a limited impetus to Northwest to open up its system to other markets. Thus British Columbia endorsed both the sale to El Paso and the extension to Licence GL-4, both of which would foster the continuation of off-line sales to Pacific Interstate for gas exported under Licence GL-41.

5.7.2.3 Conclusions

The Board notes that approval of both the Columbia application and the approval of the application by Westcoast to increase daily quantities for Licence GL-41 will require additional facilities to ensure that all Westcoast requirements and the transport of the Columbia gas can be served on a year-round basis. The Board estimates the cost of such facilities to be approximately \$38 million.

It appears to the Board that the marketing problems in the Pacific Northwest market served by Licence GL-41 not only affect deliveries under that licence, but also are important in the Board's consideration of the applications to extend Licence GL-4 and to increase the daily and annual quantities under Licence GL-41 for the sale to El Paso. The Board notes that to the extent it is in the public interest to foster a higher annual load factor under Licence GL-41, the extension of Licence GL-4 and the El Paso sale would contribute to that end.

5.7.3 Other Matters

5.7.3.1 Evidence

Westcoast believed that there was great merit in extending licences like GL-4 that have the transportation capacity to deliver the gas to market without incremental costs. It suggested a number of additional factors to be considered in determining priorities among applications, including whether the market had been previously served, the significance of Canadian gas to the customer, and the overall benefits to Canada.

Westcoast suggested that the most significant benefit of the extension to Licence GL-41 was that it would enable Westcoast to arrange an orderly reduction in the export of gas. It was argued that the extension deserved priority because of the significant impact that sales under Licence GL-41 had upon the Westcoast system and upon the producing industry in British Columbia. Westcoast warned that inasmuch as the quantities exported under Licence GL-41 were projected to be 50 percent of the total Westcoast throughput, not extending its term beyond 1989 would cause enormous distortions that would ultimately effect its domestic customers. Furthermore, it believed that exploration and development activity would decline in British Columbia well in advance of the expiry date.

5.7.3.2 Conclusions

Westcoast was not requested to undertake a cost-benefit analysis. However, the Board did prepare such an analysis, which pertained to the proposed extension of Licence GL-4, to the proposed amendments to the daily maximum quantities under Licence GL-41, and to the proposed extension of Licence GL-41.

In the view of the Board, the Westcoast proposal to extend existing export Licence GL-4 with catch-up provisions would result in net benefits to Canada of \$467 million based on the export of $7\,932 \times 10^6 \text{ m}^3$. The amendment to GL-41 to facilitate the El Paso contract would result in net benefits of \$334 million based on the export of $6\,204 \times 10^6 \text{ m}^3$. The Westcoast proposal to extend existing export Licence GL-41 with catch-up provisions would result in net benefits to Canada of \$752 million assuming the export of $33\,144 \times 10^6 \text{ m}^3$. These present value estimates are in 1978 dollars at a ten percent discount rate.

5.8 The Joint Application

Although the Joint Applicants, Pan-Alberta, TransCanada, and Consolidated, presented their evidence together, for clarity the Board has

dealt with the Joint Applicants on an individual basis, except for their evidence with regard to surplus determination.

The Joint Applicants recalculated the Current Reserves Test as of 31 March 1979 by re-estimating current reserves and adjusting Alberta protection from 30A1 to 25A1 to reflect the recent decision in this regard of the AERCB.

The Joint Applicants estimated total Canadian deliverability from existing reserves through the utilization of a computer model that forecasts the deliverability from reserves in Alberta and British Columbia on a pool-by-pool basis. Using this technique, the Joint Applicants showed a deficiency in supply capability in the Current Deliverability Test in 1988 and a deficiency in the tracking case in 1987, if the total export volume it applied for is taken into consideration. If only the firm portion of the application were considered, the tracking case could be extended until 1988.

For the Future Deliverability Test, the Joint Applicants used the Board's high case for reserves additions shown in the 1979 Gas Report. These were assumed to be connected over an eight-year period commencing one year after the year of discovery. Using this assumption, the Joint Applicants were able to track NEB demand plus currently authorized exports to at least the year 2000. However, when the applied-for exports were included, the first year of deficiency occurred in 1996.

5.8.1 Pan-Alberta

5.8.1.1 Supply, Deliverability and Requirements

5.8.1.1.1 Evidence

Pan-Alberta submitted detailed estimates of reserves under those lands for which it held gas purchase contracts. These estimates indicated that after production to 31 December 1977 there remained reserves of 6.55 EJ ($168 \times 10^9 \text{ m}^3$) proved and 2.17 EJ ($55 \times 10^9 \text{ m}^3$) probable under contract to Pan-Alberta. Subsequent revisions by Pan-Alberta to individual pool estimates resulted in revised remaining reserves estimates of 6.6 EJ ($169 \times 10^9 \text{ m}^3$) proven and 2.5 EJ ($64 \times 10^9 \text{ m}^3$) probable under contract to Pan-Alberta. These estimates included the reserves that were under contract to Sulpetro.

The gas purchase agreements signed by Pan-Alberta were deliverability-type contracts. The term of the contracts, as amended, was for 12 years or until the expiry of its Alberta removal permit or of its export licence, whichever occurred first.

Pan-Alberta is the holder of AERCB Permit No. PA 74-1, which authorizes it to remove a quantity of gas not to exceed 1 053 PJ (975 Bcf at 14.65 psia) during the period from 1 November 1974 to 31 October 1989, at a daily rate not exceeding 313.3 TJ (290 MMcf), and at an annual rate not exceeding 108.0 PJ (100 Bcf).

In its Report 79-C of July 1979, AERCB stated that subject to approval by the Lieutenant Governor in Council, it was prepared to grant Pan-Alberta a permit authorizing the removal of 3 710 PJ ($95.0 \times 10^9 \text{ m}^3$) of gas during the 15-year period commencing 1 November 1980 and terminating 31 October 1995. Maximum daily quantities were not to exceed 1 183 TJ ($30.3 \times 10^6 \text{ m}^3$), with annual quantities no greater than 345 PJ ($8.84 \times 10^9 \text{ m}^3$).

Pan-Alberta stated that it had applied to AERCB on 20 July 1979 requesting an additional 15-year term removal permit covering the same period. The additional quantity under this permit would be 4.73 EJ (4.3 Tcf at 14.65 psia), with daily and annual quantities of 935 TJ (850 MMcf), and 352 PJ (320 Bcf) respectively. Furthermore, TransCanada had undertaken to sell to Pan-Alberta up to 746.7 PJ (700 Bcf at 14.65 psia) so as to assure Pan-Alberta an adequate supply. Of this amount, some 426.7 PJ (400 Bcf) was stated to be currently under permit.

In addition, Pan-Alberta had contracted to purchase from Alberta and Southern a maximum daily quantity of 218.4 TJ (200 MMcf at 14.65 psia) and an annual quantity of 79.7 PJ (73.0 Bcf), at a 100 percent load factor. The termination date of the contract was 31 October 1986 or the date when Pan-Alberta's or Alberta and Southern's removal permits expire, or the date when Pan-Alberta's export licence expires, whichever occurs first.

Pan-Alberta submitted a summary of producer deliverability forecasts based on its controlled reserves. This summary was derived by totalling the pool estimates for consecutive life years. The forecast demonstrated a constant decline in deliverability for the 25-year period. Pan-Alberta stated that the forecast did not purport to represent the manner in which the gas would actually be produced.

Pan-Alberta submitted a supply and requirements forecast for an expanded case, shown in Table 5.8.1.1, reflecting all potential requirements Pan-Alberta might have to serve, subject to obtaining appropriate regulatory

approvals. The expanded case included domestic requirements for the Q & M project and the proposed exports to be made via Foothills. The supply included its new contracted quantities, quantities under AERCB Permit No. PA 74-1 and supply from Alberta and Southern, but did not include the proposed purchase of 746.7 PJ (700 Bcf at 14.65 psia) from TransCanada.

Pan-Alberta's evidence demonstrated that supply tracking of its total requirements could be maintained for five years before a deficiency of 14.5 PJ (13.2 Bcf at 14.65 psia) occurred in the contract year 1985-86. The deficiency was shown to increase to a maximum of 445.9 PJ (405.3 Bcf) by the year 1992-93.

Pan-Alberta indicated that without the Q & M requirements and without supply available under AERCB Permit No. PA 74-1, but including the A & S annual supply of 79.7 PJ (73 Bcf at 14.65 psia), it could meet its requirements for about 9.5 years before a supply deficiency would occur. However, Pan-Alberta stated that there would be a shortfall in Alberta and Southern's supply commitment throughout its six-year contract term with Pan-Alberta. Nevertheless, Pan-Alberta stated that Alberta and Southern felt it would be successful in acquiring adequate supply to meet its commitments.

Pan-Alberta indicated that additional supply necessary to meet total growth in the Q & M market area and for the continuation of exports would be acquired through expansion of existing purchase contracts with producers in currently contracted areas and through the purchase of gas in new areas and from TransCanada.

Pan-Alberta has the following Canadian obligations:

(1) Gaz Métropolitain	- 142.9 PJ (134 Bcf at 14.65 psia) (1 Nov 79 - 31 Oct 89)
(2) Westcoast	- 411.6 PJ (381 Bcf) (1 Nov 79 - 31 Oct 89)
(3) Sulpetro	- 10.1 PJ (9.5 Bcf) (1 Nov 79 - 31 Oct 80)
(4) Alberta consumption	- 24.8 PJ (23 Bcf) (1 Nov 79 - 31 Oct 89)
Total	589.4 PJ (547.5 Bcf)

5.8.1.1.2 Conclusions

After giving consideration to the evidence, the Board estimates that the remaining established reserves available to Pan-Alberta are 4.6 EJ in fields listed in its new AERCB Permit No. PA 79-2. The Board concludes that it is this which Pan-Alberta has available to it to dedicate to its various future projects, including the proposed exports. Of that amount, seven percent would be required for Alberta fuel use and shrinkage.

In reviewing the reserves data submitted by Pan-Alberta, the Board concludes that many of Pan-Alberta's reserves evaluations involve potential reserves that will require additional drilling before being classified as established reserves by the Board. The Board notes, however, that there is opportunity for substantial reserves appreciation in many pools.

The Board's forecast of Pan-Alberta's deliverability reflects that Pan-Alberta's export requirements, including fuel requirements, can be met until 1985. The forecast, shown in Table 5.8.1.1 and Figure 5.8.1.1, shows the Board's estimate of currently established reserves in Pan-Alberta's new supply areas, covered by its AERCB Permit No. PA 79-2, plus supply available from Sulpetro after 1982 and the quantities estimated to be available from Alberta and Southern. With regard to the latter, the Board forecasts that only a small amount of gas will be available from A & S because of the set-aside procedure used by the Board for protecting existing licence quantities. In actual practice, the ability of A & S to supply gas to Pan-Alberta will depend upon the level of other demands on Alberta and Southern's supply, including export requirements.

The Board's forecast does not take into consideration Pan-Alberta's existing requirements now being met from supply available under AERCB Permit No. PA 74-1, or those future potential requirements of Pacific Northern and the Q & M project. Thus, Pan-Alberta's forecast, contained in Table 5.8.1.1, which did reflect these other requirements, and the Board's supply and requirements forecast, shown in Table 5.8.1.1, are not directly comparable.

5.8.1.2 Facilities, Markets, and Contracts

5.8.1.2.1 Evidence

Pan-Alberta proposes to export natural gas from Alberta through the prebuilt facilities of Foothills. Prebuilt facilities for the eastern leg, to carry gas for export at Monchy, Saskatchewan, would involve the construction of a

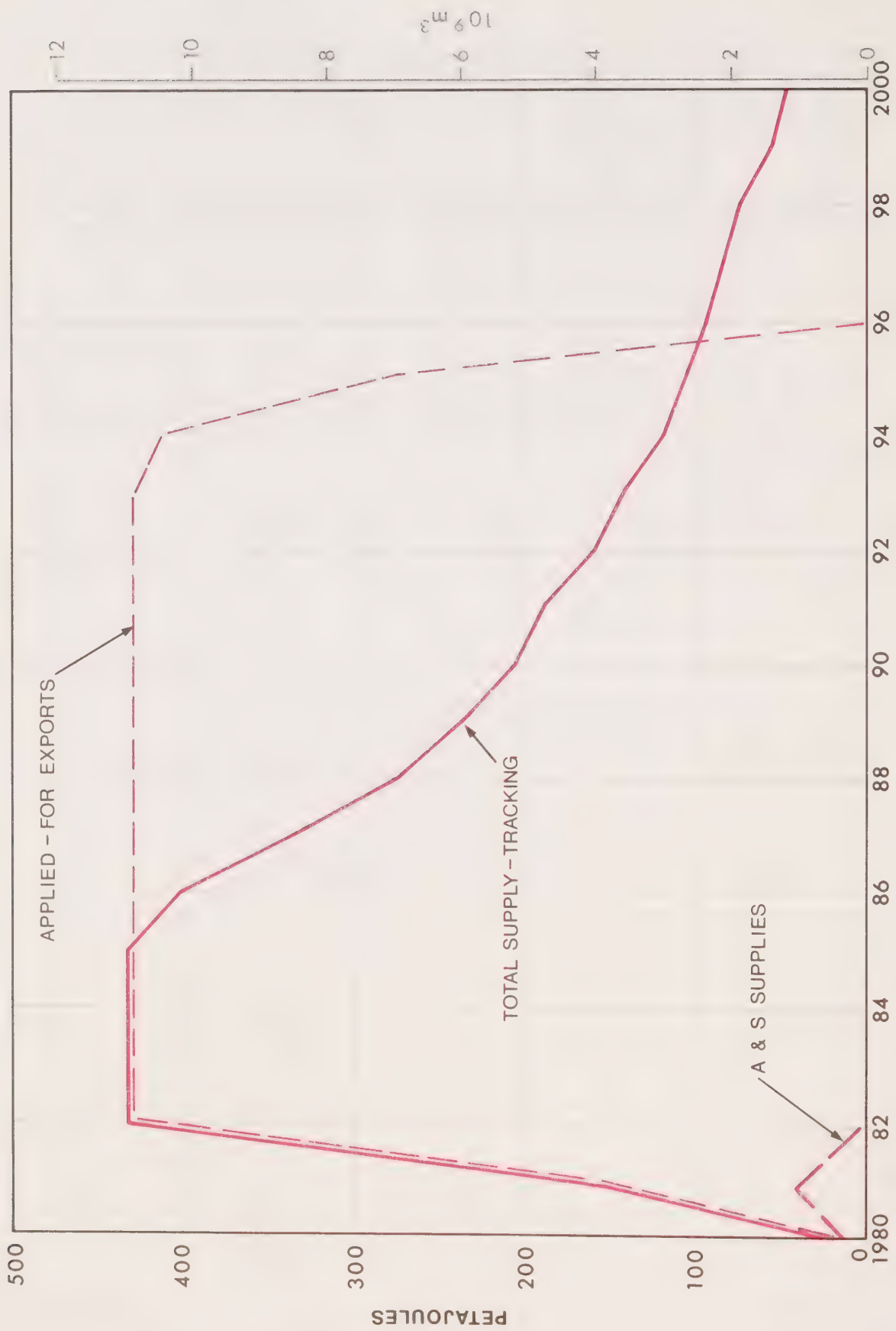
Table 5.8.1.1.1

PAN-ALBERTA

SUPPLY/DEMAND

YEAR	PAN-ALBERTA FORECAST				NEB FORECAST	
	(As Filed)		(Converted by NEB)		Annual Demand (PJ)	Annual Supply (PJ)
	Annual Demand (1) (Bcf)	Annual Supply (1) (Bcf)	Annual Demand (PJ)	Annual Supply (PJ)		
1980	167.9	167.9	184.7	184.7	16.6	16.6
81	523.0	523.0	575.4	575.4	154.7	154.7
82	550.9	550.9	606.1	606.1	430.1	430.1
83	581.1	581.1	639.4	639.4	430.1	430.1
84					430.1	430.1
1985	612.5	612.5	673.9	673.9	430.1	430.1
86	626.2	613.0	689.0	674.5	430.1	400.6
87	641.6	408.6	705.9	449.6	430.1	333.0
88	656.9	442.1	722.8	486.4	430.1	273.0
89	671.0	400.2	738.3	440.3	430.1	233.2
1990	645.7	362.3	710.5	398.6	430.1	206.8
91	654.4	328.0	720.0	360.9	430.1	180.9
92	665.5	297.0	732.2	326.8	430.1	159.2
93	674.2	268.9	741.8	295.9	430.1	140.0
94	589.7	243.5	648.8	267.9	413.5	119.7
1995	282.2	220.6	310.5	242.7	275.5	106.7
96						94.4
97						84.1
98						74.9
99						55.2
2000						47.8

Source: (1) Exhibit No. 8-38. Table 2, Cols. H & I. (at 14.65 psia and 60°F).



PAN - ALBERTA
Annual Requirements vs. Supply

total of 630.4 km (394 miles) of 1 050-mm (42-inch) pipeline and two compressor stations, costing in total \$355.3 million, in 1979 dollars. The western leg, to carry gas for export at Kingsgate, B.C., would comprise a total of 382.4 km (239 miles) of 900-mm (36-inch) pipeline and one compressor station, costing in total \$145 million, in 1979 dollars. The total capital cost of the project would be \$500.3 million in 1979 dollars, not including allowance for funds used during construction.

In order to deliver Pan-Alberta gas to Foothills, additional facilities would have to be constructed on the AGTL system, including additions to gathering and mainline facilities. No firm estimate of the cost of the AGTL facilities required could be given by Pan-Alberta, since the pattern of connection of the gas supply had not yet been determined.

Pan-Alberta's United States customer is Northwest Alaskan. The gas to be exported at Monchy, Saskatchewan would be sold by Northwest Alaskan as follows:

- (1) To Northern Natural - $5.66 \times 10^6 \text{ m}^3$ (200 MMcf) per day
- (2) To Panhandle - $4.24 \times 10^6 \text{ m}^3$ (150 MMcf) per day
- (3) To United - $12.75 \times 10^6 \text{ m}^3$ (450 MMcf) per day

The gas to be exported at Kingsgate would be sold by Northwest Alaskan to Pacific Interstate.

United, through its subsidiary, United Mid-Continent Pipeline Company, is a partner in Northern Border. An affiliate of United, ANB, expects to be a shipper of the gas through the Northern Border system. United will purchase Alberta gas from ANB at the terminus of the Northern Border facilities near Ventura, Iowa, where the gas will be exchanged with that of Northern Natural for like quantities of Gulf Coast production that will be delivered into United's system. As the gas would represent 15 to 20 percent of United's 1978 curtailed sales, it would serve only existing curtailed customers.

Northern Natural will be a shipper through the Northern Border pipeline. Its wholly-owned subsidiary, Northern Plains Gas Company, will be a partner in and the operator of the Northern Border pipeline. Northern Natural testified that the quantities it has contracted to purchase from Northwest Alaskan would be sold in its service area to alleviate curtailment of deliveries to its existing gas customers.

Panhandle serves major market areas in Kansas, Missouri, Illinois, Indiana, Ohio, and Michigan. Panhandle is a partner in the Northern Border pipeline through a subsidiary company formed by its parent corporation and will be a shipper through the Northern Border system. It will move the quantities of gas to its markets via two transportation agreements, one with Northern Natural and the other with Northern Border. The gas will be sold in Panhandle's market areas to serve "Priority 1"⁽¹⁾ customers.

Pacific Interstate has entered into transportation agreements with PGT, Northwest, and El Paso. The ultimate destination of the gas would be the market served by SoCal, which serves a large portion of California, including metropolitan Los Angeles. SoCal indicated that "Priority 1" customers are not currently suffering curtailment during normal weather conditions, although service to commercial and industrial accounts of lower priority was expected to decline rather significantly over the next few years. The proposed imports would account for approximately five to six percent of SoCal's existing demand level.

Pan-Alberta had not finalized transportation contracts with either AGTL or Foothills to carry the export quantities, in part because the Foothills tariff had not yet been set.

The gas sales contracts dated 9 March 1978 provided that if Pan-Alberta's gas supply were insufficient to satisfy all of its delivery obligations, all of its customers would be curtailed on a pro rata basis except for those specified, those being Westcoast, Gaz Métropolitain, and Pacific Northern. Deliveries for Alberta fuel and shrinkage requirements also would not be curtailed. The contracts also contained take-or-pay provisions requiring Northwest Alaskan to take at least 50 percent of the daily contract quantity and to take-or-pay for 85 percent of the annual quantity. Northwest Alaskan stated that it intended to take gas at the full 100 percent load factor. The contracts provided for the sale of:

(1) United States regulatory agencies define "Priority 1" requirements as those residential, small commercial, and industrial sales of less than 50 Mcf (1 416 m³) on a peak day.

- (1) $22.6 \times 10^6 \text{ m}^3$ (800 MMcf) per day at Monchy, for the period 1 November 1981 to 31 October 1994,
- (2) $6.8 \times 10^6 \text{ m}^3$ (240 MMcf) per day at Kingsgate, for the period 1 November 1980 to 31 October 1993.

5.8.1.2.2 Conclusions

The Board finds that there are no market or contractual matters that conflict with this proposed export.

5.8.1.3 Other Matters

5.8.1.3.1 Evidence

It was Pan-Alberta's view that the Board should give top priority to the Joint Application and, if there were still sufficient quantities to serve other licence applications, the Board could allocate the balance as it deemed appropriate. Pan-Alberta believed its application to be in the best interest of Canada and all segments of the gas industry because the exports being sought would assist in ensuring the economic viability of the ANGTS, would make use of available capacity in the TransCanada system, and would provide for the continuation of an export commitment with respect to Licence GL-1.

The Joint Applicants believed that prebuilding was important to the realization of the entire ANGTS because it would help with the financing, assist in the marshalling of manpower and equipment, provide a stimulus to exploration and development activity, especially among the smaller Canadian-owned independents, prevent dilution of Canadian equity ownership in the oil and gas industry, provide substantial employment and consumer benefits, and provide revenues to all levels of government.

Pan-Alberta suggested that because of the interrelationship between the prebuilt facilities and the entire ANGTS, its export proposal would be the cheapest method of exporting gas and would therefore bring the highest return to producers and the various levels of government. In addition, because the Canadian gas to be exported through the prebuilt facilities was backed up by Alaskan gas, U.S. customers could not claim dependency on Canadian gas at some future date.

In Pan-Alberta's opinion, United States energy policy favoured gas imports perceived to support the ANGTS, and that such a policy favoured the Joint Application.

Pan-Alberta provided a cost-benefit analysis that assessed the incremental benefits and costs to Canada of exporting natural gas on the prebuilt facilities of Foothills. The export of $139.9 \times 10^9 \text{ m}^3$ (4.9 Tcf) of Alberta gas over the period 1980 to 1994 via the prebuilt facilities was compared with the alternative of constructing the entire Foothills system over the period 1980 to 1984 for the purpose of transporting only gas from Alaska to the United States over the period 1984 to 2009. The differences between these two alternatives were taken to represent the incremental benefits and costs to Canada of Pan-Alberta's gas exports. Total export quantities would be transported on AGTL and on the prebuilt facilities of Foothills for export at Kingsgate, B.C. and at Monchy, Saskatchewan.

The main incremental benefits Pan-Alberta associated with its export proposal were identified to be the revenue received from the sale of natural gas and by-products and the value of any additions to gas reserves as a result of reinvestment of export revenues by producers.

Pan-Alberta made several major assumptions in estimating these benefits. First, the export price was assumed to increase in real terms from \$2.18/GJ in 1980 to \$2.27/GJ in 1994. Second, gas by-products were valued at 30 percent of the producer revenue at the field gate. Third, new reserves would be discovered, amounting to $133.1 \times 10^9 \text{ m}^3$ (4.7 Tcf), which would be in addition to the $139.9 \times 10^9 \text{ m}^3$ (4.9 Tcf) required to replace the export quantities. These were valued at \$2.04/GJ and were assumed to be sold in Canadian markets over the period 1999 to 2009.

The main incremental costs associated with the export proposal included the incremental resource costs (both capital and operating) resulting from prebuilding the Foothills facilities and the increased expenditure of the gas producing sector. Major costs associated with the export proposal were estimated by Pan-Alberta to be as follows:

Capital costs:

Development, gas processing, and gathering facilities

\$228 million

Other costs:

	<u>Per GJ</u>	<u>Per Mcf</u>
Lifting	\$0.19	\$0.20
Processing	\$0.23	\$0.25
AGTL cost of service	\$0.13	\$0.135

While, in general, prebuilding required the shifting forward in time of the capital expenditures associated with building the Foothills pipeline, the net result was an estimated real increase in capital costs of \$186 million. The additional operating costs of Foothills arising from the export of the proposed quantities were included as an incremental cost of the Foothills project. However, the present value of this cash flow estimated by Pan-Alberta was negative with the result that this item increased the benefits.

Pan-Alberta listed several other benefits that it considered to be important in an overall assessment of its export proposal. These included a favourable effect on Canada's balance of payments; enhanced prospects for Canadian energy self-sufficiency because the project could lead to a net increase in Canada's marketable reserves and less costly access to Northern gas; and an opportunity for greater efficiency in the gas producing industry because of economies of scale and incentives for technological changes.

In addition, Pan-Alberta claimed that the project would have positive employment effects, be beneficial to Canadian manufacturing, have a negligible effect on wage and price levels, have a stabilizing influence on the economy over the short run, and would provide a cash flow for financing other energy projects, particularly by Canadian firms.

The main result of the Pan-Alberta analysis was that net benefits of approximately \$4,550 million (present value in 1978 dollars based on a ten percent discount rate) would accrue to Canada based on the proposed export of $139.9 \times 10^9 \text{ m}^3$ (4.9 Tcf). This was based upon estimated incremental benefits and costs of exporting Alberta gas (combined with prebuilding) relative to the case in which Foothills was constructed to transport Alaskan gas only.

Pan-Alberta undertook additional analysis to test the sensitivity of the conclusions to some of the assumptions. Three issues were examined: the effect of higher finding costs, the consequences of decisions by foreign-owned gas-producing companies to repatriate profits, and the effect of using shadow prices for labour inputs. The results were reported at discount rates of five, ten and fifteen percent as set out in Table 5.8.1.3.1.

Pan-Alberta also submitted a formal macroeconomic impact study, using an econometric model of the Canadian economy to simulate economic activity under the following three cases: (1) Foothills with prebuilding and short-term exports, (2) Foothills with no prebuilding or exports, and (3) no Foothills pipeline.

Data was presented showing the effects of these cases on GNP, employment and the unemployment rate, wages and prices, Federal Government revenue and expenditure balance, and the current account balance.

The study concluded that in all instances the construction and operation of a pipeline would produce a net expansion in the national economy, but that Case 1 (Foothills with prebuilding and short-term exports) was considerably more attractive than Case 2 (Foothills with no prebuilding or exports). The attractive features of prebuilding were stated to be its earlier investment start-up, a smoother investment pattern over time, and larger export earnings.

Table 5.8.1.3.1

PAN-ALBERTA

ESTIMATES OF THE PRESENT VALUE OF NET BENEFITS
ASSOCIATED WITH THE PAN-ALBERTA PROJECT
(millions of 1978 dollars)

<u>Discount Rates</u>	<u>5%</u>	<u>Net Benefits</u>	
		<u>10%</u>	<u>15%</u>
1. Base Case	8,305.3	4,549.9	2,854.7
<u>Alternative Assumptions</u>			
2. Assuming higher cost reserves replacement (conventional area)	5,214.5	3,550.6	2,508.9
3. Assuming higher cost reserves replacement and additional transportation costs (Mackenzie Delta)	4,509.9	3,360.7	2,451.5
4. Assuming greater financial capital outflows	7,026.5	3,692.3	2,251.9
5. Assuming shadow price for labour input	(no significant change to base case)		

Compared with Case 3 (no Foothills pipeline) it was estimated that Case 1 would result in an increase in the GNP level by 1994 of 2.0 percent and that Case 2 would result in a 1.1 percent increase. The simulations also suggested that during the investment phase about 350,000 man-years of employment would be

added over the period 1980-84 in Case 1 as compared with 200,000 man-years in Case 2. With respect to the current account balance, both Case 1 and Case 2 were shown to have an initial negative effect on the current account; however, this effect turned positive by 1982 in Case 1 and by 1985 in Case 2. The inflationary impact of both cases was estimated to be relatively small.

Pan-Alberta suggested that while increased gas exports would draw on reserves, they would also produce additions to recognized reserves through the generation of cash flow and its subsequent reinvestment in exploration and development activity. Based on historical finding costs and its estimate of industry reinvestment, Pan-Alberta estimated that its additional exports could result in marketable reserves additions by 1994 of $273.6 \times 10^9 \text{ m}^3$ (9,658 Bcf), which exceed the proposed export quantities of $139.9 \times 10^9 \text{ m}^3$ (4,935 Bcf) by a significant margin. The company concluded that, consequently, gas reserves available for domestic use could be larger with increased short-term exports than would be the case without such exports, even if finding costs were to increase significantly.

5.8.1.3.2 Conclusions

The Pan-Alberta cost-benefit study incorporated several features that were different from the studies submitted by others. The results of the study were based entirely upon the successful completion of the Foothills pipeline for the purpose of transporting Alaskan gas.

In estimating the opportunity cost associated with the export quantities, Pan-Alberta assumed in its original filing that if export sales were not made, the reinvestment by gas producers and subsequent gas discoveries would not occur, with the result that these additional net benefits would not be realized. In response to a request, Pan-Alberta filed an alternative study during the Hearing based on the assumption that, if export sales were not made, later sales would be made in the Canadian market.

Pan-Alberta valued by-products associated with natural gas production at 30 percent of the producer revenue at the field gate. In the Board's view, this estimate is too high and the Board has estimated the value of by-products at 20 percent of the value of gas exported.

The reinvestment of a portion of gas producers' receipts from the proposed exports was viewed as a direct cost of the project, and the associated discoveries were considered a direct benefit. It is the view of the Board that

benefits and costs of this nature represent possible indirect effects which would be contingent on assumptions contrary to those of cost-benefit analysis and, accordingly, the Board has excluded them from its study.

Pan-Alberta estimated that the present value of the amount of financial income received by Foothills from investing temporarily idle funds was positive. The Board views such investment income as outside the scope of cost-benefit analysis.

In the view of the Board, the Pan-Alberta export proposal would result in net benefits to Canada of \$4,789 million (present value in 1978 dollars at a ten percent discount rate) based on the proposed export of $139.9 \times 10^9 \text{ m}^3$ (4.9 Tcf). As the Board assumed a higher gas export price, its estimate of net benefits was greater than that of Pan-Alberta.

5.8.2 TransCanada

5.8.2.1 Supply, Deliverability and Requirements

5.8.2.1.1 Evidence

TransCanada submitted detailed estimates of reserves for those pools within Alberta for which it had a gas purchase contract. These estimates indicated that after production to December 1978, the remaining reserves under contract to TCPL were 28.63 EJ (26.31 Tcf at 14.73 psia). These estimates do not include those reserves under contract to Consolidated.

TransCanada holds AERCB Permit Nos. TC 76-12 and GW 74-1, which authorize it to remove an annual quantity of 1 247 PJ (1,169 Bcf at 14.65 psia). As of 31 December 1978, 17.2 EJ (16.1 Tcf) remained to be removed under these permits.

TransCanada holds Saskatchewan Export Permit No. 1, which authorizes TCPL to withdraw annual quantities of 8.9 PJ (8.6 Bcf at 14.65 psia). Remaining quantities at 31 December 1978 were 12.16 PJ (11.76 Bcf).

In addition to gas available to TCPL under its own permits, TransCanada purchases gas from other permit holders. TransCanada had 2.38 EJ (2.23 Tcf at 14.65 psia) remaining available to it as of 31 December 1978 from these companies. This includes some 1.97 EJ (1.85 Tcf) of remaining authorized removals for Consolidated under AERCB Permit No. CNG 69-1.

TCPL submitted both a deliverability forecast, based on the current performance of its various collection points and on information supplied by producers, and a supply-demand balance, demonstrating that its supply could meet its requirements until 1985. Furthermore, TransCanada's forecast included some allowance for anticipated appreciation of reserves under contract. It indicated that if Pan-Alberta's purchases from it were less than the full 106.7 PJ (100 Bcf at 14.65 psia) of gas during the three years preceding 1985, the deficiency occurring in that year would be reduced or even eliminated.

TransCanada stated that it intended to purchase additional gas supply prior to 1985 to maintain a supply position of sufficient strength whereby requirements could be met from a level of supply related to minimum contract obligations.

TransCanada's forecast of its requirements for the period 1 November 1979 to 31 October 1990, which is contained in its supply-demand balance (Table 5.8.2.1), estimated its requirements for domestic sales, existing and proposed export sales, for company fuel, losses, and other uses, as well as for transportation and storage transportation to be 19.76 EJ (18.254 Tcf). This forecast makes allowance for the potential increase in demand resulting from the expansion of existing markets and from the expansion of the franchise area beyond Montreal. The forecast excludes, however, TransCanada's potential sale to Pan-Alberta of 106.7 PJ (100 Bcf at 14.65 psia) per year or 746.9 PJ (700 Bcf) over a seven-year period.

5.8.2.1.2 Conclusions

After giving consideration to the evidence, the Board estimates that the remaining established reserves available to TransCanada, excluding those reserves contracted to Consolidated, are 25.79 EJ. The Board has estimated Consolidated's established reserves remaining under AERCB Permit No. CNG 69-1 as of December 1978 to be 1.54 EJ, which are dedicated to TransCanada.

The Board's forecast of TransCanada's total deliverability from established reserves, shown on Table 5.8.2.1 and Figure 5.8.2.1, indicates that all of TCPL's requirements, both existing and applied for, can be met until 1985.

The Board's estimate of TransCanada's requirements is higher than that shown by TransCanada for most years of the forecast, mainly because of the quantities the Board has set aside for existing licences served by TCPL.

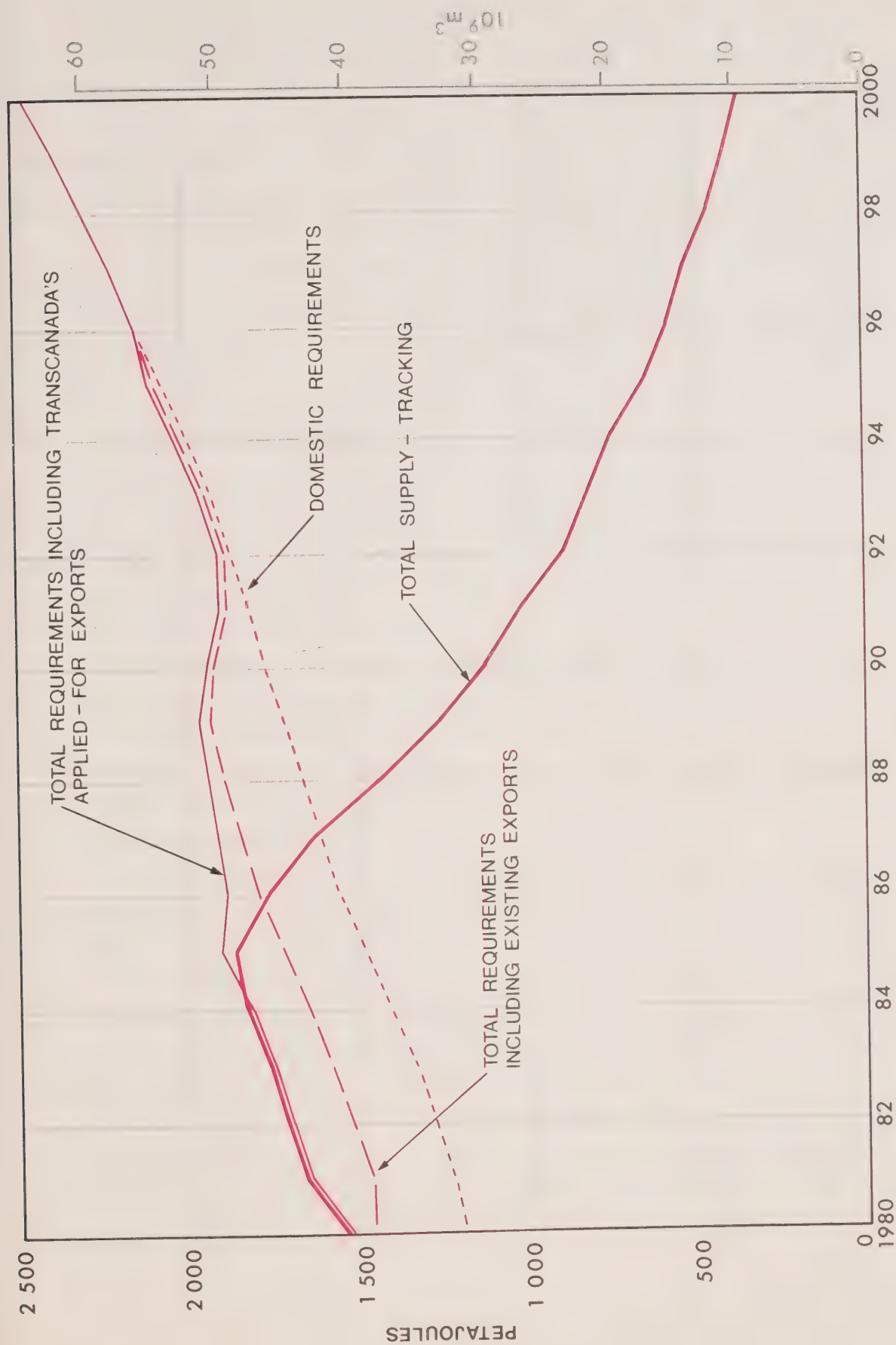
Table 5.8.2.1

TRANSCANADA

YEAR	SUPPLY/DEMAND TRANSCANADA FORECAST						NEB FORECAST	
	(As Filed)		(Converted by NEB)				Annual Demand (PJ)	Annual Supply (PJ)
	Annual Demand (1) (Bcf)	Annual Supply (1) (Bcf)	Annual Demand (2) (PJ)	Annual Supply (2) (PJ)	Annual Demand (2) (PJ)	Annual Supply (2) (PJ)		
1980	1469	1469	1590	1590	1590	1542	1542	
81	1506	1506	1630	1630	1630	1653	1653	
82	1544	1544	1671	1671	1671	1709	1709	
83	1590	1590	1721	1721	1721	1763	1763	
84	1645	1645	1781	1781	1781	1834	1834	
1985	1717	1708	1859	1849	1849	1905	1859	
86	1687	1619	1826	1752	1752	1877	1760	
87	1719	1529	1861	1655	1655	1905	1614	
88	1768	1441	1914	1560	1560	1938	1436	
89	1805	1350	1954	1461	1461	1960	1255	
1990	1804	1252	1953	1355	1355	1932	1125	
91						1883	1008	
92						1894	899	
93						1954	819	
94						2023	744	
1995						2091	645	
96						2145	580	
97						2212	518	
98						2294	459	
99						2378	406	
2000						2468	359	

Source: (1) Exhibit 12-35, Tab 2. (at 14.65 psia and 60°F).

(2) Adjusted to track demand until deficient - Includes appreciation.



TRANSCANADA
Annual Requirements vs. Supply

Furthermore, while TCPL's forecast included allowance for anticipated reserves appreciation, no such provision is contained in the Board's forecast.

Although both forecasts indicate deficiencies in deliverability occurring in 1985, they are not strictly comparable, with the Board's forecast reflecting a significant drop in supply after 1987.

The Board notes that neither it nor TransCanada included the proposed TCPL sale to Pan-Alberta of up to 107 PJ annually (100 Bcf at 14.65 psia) commencing in 1982. However, contrary to TransCanada's evidence, should such sales to Pan-Alberta take place, the Board concludes that shortfalls in TransCanada's capability to meet requirements would occur earlier than 1985.

5.8.2.2 Facilities, Markets and Contracts

5.8.2.2.1 Evidence

Because the proposed extension of Licence GL-1 would continue existing deliveries on its Western Section from Empress to Emerson, TransCanada testified that no new facilities would have to be built in order for this export to take place. However, TransCanada stated that there was not sufficient spare capacity on its system to permit it to carry all of the new proposed export quantities which would use TCPL facilities. These include the export quantities proposed by Sulpetro, Niagara, Consolidated, and ProGas. Accordingly, TransCanada described certain system expansion options it had considered to meet a variety of capacity requirements arising not only from possible new export deliveries but also from market expansion in Eastern Canada. It stated that its present plans were to undertake a limited further expansion of its system until 1981, when it planned to have a system capacity of $36.1 \times 10^9 \text{ m}^3$ (1,274 Bcf), which would accommodate the Consolidated and system growth requirements. On the assumption that the proposed Consolidated exports would shift to the Foothills system in 1981, TCPL would have adequate capacity until 1983-84. At that time, rather than undertake further system expansion, TransCanada proposed to commence shipping further growth requirements via Foothills (Sask.) and the Northern Border pipelines for eventual redelivery to Eastern Canada by exchange. Only some $425 \times 10^6 \text{ m}^3$ (15 Bcf) would be shifted to Foothills in 1983-84, according to TCPL's forecasts, but these quantities were shown to grow to $6\,969 \times 10^6 \text{ m}^3$ (246 Bcf) in 1989-90.

TransCanada acknowledged that at the time of the approval of the Great Lakes pipeline system, TransCanada had made an agreement with the Canadian Government to eventually ship at least 65 percent of gas destined to Eastern

Canadian markets through its Northern Ontario sections. TransCanada gave evidence that this flow is currently slightly below the 65 percent level and acknowledged that the diversion of its gas as proposed to the Foothills/Northern Border pipelines could cause the flow to be below the 65 percent level in the late 1980's. However, TransCanada believed that, if necessary, it could renegotiate its agreement with the federal government.

TransCanada's United States customer, Midwestern, owns and operates two separate large diameter pipeline systems. Midwestern's Northern System extends from a point of interconnection with TransCanada's facilities near Emerson, Manitoba and runs in a southwesternly direction to Marshfield, Wisconsin. Midwestern supplies Canadian gas to markets in Minnesota, North Dakota, and Wisconsin from its Northern System.

Midwestern also sells gas purchased under Licence GL-1 to Michigan Wisconsin for resale to various distributors in Missouri, Iowa, Illinois, Tennessee, Indiana, Ohio, Wisconsin, and Michigan, as well as to various municipally-owned and private distributors in Minnesota, North Dakota, and Wisconsin. Michigan Wisconsin would continue to purchase gas from Midwestern should the GL-1 extension be approved.

The Minnesota PSC, the Midwestern Customer Group, Midwestern, the North Dakota PSC, and Michigan Wisconsin all filed interventions in support of this application. The prevailing argument tendered by each intervenor was that the communities served by Midwestern's Northern System are "full-requirement" communities and that GL-1 currently accounts for a least 60 percent of the gas supply available to this system.

TransCanada stated that the existing sales contract dated 14 April 1960 between TCPL and Midwestern would provide for the quantities proposed to be exported under the GL-1 extension. This sales contract became effective on 15 December 1960 and runs for a period of 25 years to 15 December 1985. The quantities currently being exported and those proposed for the extension of the licence are compatible with the daily and annual quantities as contained in the existing sales contract.

5.8.2.2.2 Conclusions

The Board notes that forecast growth in the gas requirements of Eastern Canada, and especially in the "market expansion" scenario, will require considerably higher pipeline capacity by the late 1980's. Under certain

circumstances, the approval of export deliveries that would bring about earlier pipeline expansion than would otherwise be the case might be desirable if the expansion did not result in significant idling of facilities after the exports terminated and if the cost of the new facilities could be at least partially recovered on the strength of the export deliveries. In this regard, the Board has assessed the costs and benefits of various facilities additions to the TCPL system required by various export approval scenarios. This is discussed in Chapter 7.

The Board notes that TransCanada's proposed diversion of gas commencing in 1983-84 to the eastern leg of the ANGTS is a concept only and is not a matter requiring a Board decision at this time. In that regard, the Board believes, as a general principle, that it is preferable for Canadian gas to move in Canadian pipelines to Canadian markets.

The Board finds that there are no contractual or market issues that conflict with the proposed export.

5.8.2.3 Other Matters

5.8.2.3.1 Evidence

A cost-benefit study was submitted jointly by TCPL and Consolidated, which assessed the net economic benefit of exporting $28.2 \times 10^9 \text{ m}^3$ (994 Bcf) of natural gas as compared with the alternative of producing gas later for the domestic energy market. Total export quantities would be transported on the AGTL and TCPL systems to the export point at Emerson, Manitoba. The additional facilities required to implement the export proposal would include the construction of 102 km (64 miles) of 105-mm (42-inch) loop on the Western Section of TCPL's system, and some expansion of the AGTL system.

In the alternative, it was assumed that if exports were not permitted, the same gas would be contracted for domestic use between the years 1999 and 2018. These quantities would also be transported on the AGTL and TCPL systems.

Revenue from the export sale of natural gas, revenue earned by producers from the sale of associated fuel gas, and the net social benefit associated with the increased production of a replacement fuel for the exported quantities were considered to be the major benefits of the TCPL and Consolidated export proposals.

The major assumptions used in estimating these benefits included: an export price that was forecast to increase in real terms from \$2.30/GJ in 1979 to \$2.63/GJ in 2000; fuel requirements for the TCPL and AGTL systems

that were estimated to be equal to five percent and one percent respectively of throughput quantities; and an average Alberta border price for domestic sales that was forecast to increase in real terms from \$1.29/GJ in 1979 to \$2.08/GJ in 2000.

The costs assessed in the study included the petroleum industry's costs, the transportation costs, and the opportunity cost of the natural gas that would be exported. Major cost estimates included:

	<u>Per GJ</u>	<u>Per Mcf</u>
(1) Producers' operating costs	\$0.14	\$0.15
(2) AGTL cost of service	\$0.12	\$0.13

The cost of transporting gas on the TCPL system was based on incremental TCPL capital and operating costs.

In estimating the opportunity cost associated with the export quantities, the gross benefits and costs of the alternative domestic sale between the years 1999 and 2018 were evaluated for the gas volumes under study. Gross benefits were derived from the revenue obtained from the future sale in the domestic market, based on the Toronto city-gate price of \$2.76/GJ (\$2.96/MMBtu) and from the producer revenue obtained from associated fuel sales. The petroleum industry's costs associated with the alternative domestic use were developed as described for the export case. Transportation costs were based on the forecast AGTL and TCPL unit tariffs. The opportunity cost of exporting the proposed quantities was then represented as being the difference between the gross benefits and costs resulting from this future alternative domestic use.

The study discussed the following benefits and costs that did not lend themselves easily to monetary quantification, but were considered relevant in the evaluation of the TCPL and Consolidated exports.

Benefits included possible employment of otherwise unemployed resources and economies of scale in the natural gas pipeline transportation sector and in the drilling, supply, and servicing industry. In addition, if domestic gas reserves additions increased because of the exports, security of energy supply might be enhanced. Furthermore, a large favourable impact on Canada's balance of payments was expected. Costs identified included those associated with environmental impacts, which were considered to be minimal, and costs which might arise vis-a-vis security of energy supply if, as a result of increased gas exports, oil imports increased. This latter was not expected to occur.

The main result of the TCPL and Consolidated analysis was that there would be net benefits in the order of \$860 million (present value to mid-1978 in 1978 dollars based on a ten percent discount rate) based on the proposed export of $28.2 \times 10^9 \text{ m}^3$ (994 Bcf). TCPL and Consolidated's estimate of these net economic benefits was based upon the benefits and costs of exporting Alberta gas as compared with the alternative of later sales of equivalent gas quantities when required in the domestic market.

TCPL and Consolidated undertook additional analysis to test the sensitivity of the conclusions to several of the assumptions. Three issues were examined: the consequences of decisions by foreign-owned gas producing companies to repatriate profits; the effect of various assumptions as to the future alternative energy source that might replace gas exported now; and the effect of assuming that the project would use resources which would otherwise be unemployed. The results of the TCPL and Consolidated study reported at discount rates of 5, 10, and 15 percent, were as set out in Table 5.8.2.3.1.

Table 5.8.2.3.1

TCPL AND CONSOLIDATED

ESTIMATES OF THE PRESENT VALUE (MID-1978) OF NET BENEFITS
ASSOCIATED WITH THE TCPL AND CONSOLIDATED PROPOSALS
(millions of 1978 dollars)

	<u>Discount Rates</u>	<u>Net Benefits</u>		
		<u>5%</u>	<u>10%</u>	<u>15%</u>
1. Base Case		1,091	860	679
<u>Alternative Assumptions</u>				
2. Assuming greater financial capital outflows		404	314	236
3. Assuming alternative energy replacement fuels:				
- imported oil		756	784	660
- conventional gas		1,091	860	679
- in-situ oil sands		1,093	847	618
4. Assuming unemployed resources are used for the project		3,541	2,884	2,394

TransCanada and Consolidated also presented a study demonstrating some of the impacts of their export proposal on the Canadian economy.¹ This study showed an increase in total national income over the period 1979-90 of \$4,439 million (1978 dollars), plus the creation of 2,366 man-years of direct construction employment in the project itself. Total direct revenues received by governments in Canada were estimated to be \$960 million. It was calculated that the impact on the current account balance would be a small incremental deficit in 1979, followed by a net credit amount in the years thereafter, approximating \$350 million a year during the years of peak export.

5.8.2.3.2 Conclusions

The TCPL and Consolidated cost-benefit study used a methodology for estimating the costs and benefits of the export proposal that is similar in many respects to the approach adopted by several other submitters.

The revenue earned by producers from the sale of associated fuel gas was treated as a benefit in the TCPL and Consolidated study. The Board believes it is inappropriate to treat the use of fuel gas as a benefit.

Concerning the transmission companies' costs associated with the export volumes, TCPL and Consolidated estimated the AGTL costs to be equal to the average cost of service tariff on the AGTL system. The Board believes that a detailed estimate of the incremental capital and operating costs is preferable. TCPL costs were estimated on an incremental capital and operating cost basis. However, the incremental operating costs included taxes and return on investment. In the Board's view, the return on rate base and tax components should be excluded from the estimates.

In the Board's cost-benefit analysis of the TCPL export, it found the TCPL exports would result in net benefits to Canada of \$665 million (present value in 1978 dollars at a ten percent discount rate) based on proposed exports of about $11\,614 \times 10^6 \text{ m}^3$ (410 Bcf).

The Board's estimate of TransCanada's net benefits, when combined with that of Consolidated, is greater than that of TransCanada, as the Board has taken into consideration the value of the gas by-products and has assumed a higher gas export price in its analysis.

5.8.3 Consolidated

5.8.3.1 Supply, Deliverability and Requirements

5.8.3.1.1 Evidence

Consolidated submitted a copy of its sales purchase contract with TransCanada, whereby TCPL agreed to sell gas to Consolidated.

Consolidated was authorized to remove gas from Alberta under AERCB Permit No. CNG 69-1, as amended. Under the terms of a contract between Consolidated and TransCanada dated 23 May 1972, Consolidated sells gas to TransCanada. Pursuant to this 1972 contract, Consolidated and TransCanada had entered into a Gas Resale Agreement dated 24 February 1979, which provided for TransCanada to deliver to Consolidated, commencing 1 November 1980, 214.5 TJ (200 MMcf at 14.73 psia) per day of gas for the first five years. For each of the sixth through tenth contract years the daily contract quantity will decrease by 20 percent.

TransCanada gave assurances that in addition to its other commitments it had sufficient supply to meet Consolidated's proposed export requirements of 548.1 PJ ($14.476 \times 10^9 \text{ m}^3$).

Consolidated provided an estimate of its requirements for the period 1 November 1980 to 31 October 1989, which reflected only the quantities which it had applied to export plus an allowance for shrinkage and fuel. Therefore, Consolidated's total requirements of 548.1 PJ ($14.476 \times 10^9 \text{ m}^3$) are sales that are conditional upon export authorizations arising from the present proceedings.

5.8.3.1.2 Conclusions

As Consolidated's supply is provided by TransCanada, the Board's TransCanada forecast confirms TransCanada's ability to meet all of its requirements until 1985.

5.8.3.2 Facilities, Markets and Contracts

5.8.3.4.1 Evidence

Consolidated proposed that commencing 1 November 1980, its exports would be transported to Emerson by TransCanada. However, once the Foothills prebuilt facilities were operating, it proposed to transfer 50 percent of its exports to Foothills in the first year (presumably 1982) of Foothills operations, and all of its exports to Foothills in the second and subsequent years.

TransCanada testified in support of Consolidated that if the Foothills prebuilt facilities were in operation by the end of 1981, if the Consolidated

quantities were shifted as proposed to Foothills, and if the ProGas application were not approved, no additional facilities would be required on its system to accommodate the first several years of the Consolidated export.

Consolidated would initially export its gas at Emerson, Manitoba, where it would be transported for Northern Natural by Great Lakes to a point of interconnection of the two systems at Carleton, Minnesota. Once the Foothills and Northern Border systems were operating, Consolidated would switch its gas to that system for direct delivery to Northern Natural. The gas would be added to its total system supply to serve existing customers.

TransCanada and Consolidated entered into a transportation agreement dated 24 February 1979 under which TransCanada agreed to transport the quantities specified in the gas resale contract, for a term commencing 1 November 1980 and ending with the expiration of any necessary authorizations or until TransCanada was no longer required to carry any Consolidated gas, whichever occurred first.

The gas resale and transportation contracts provided for the transfer of the gas from Emerson to Monchy, but if the switch were made within the first five years, only half the daily quantity, i.e., 107.3 TJ (100 MMcf at 14.73 psia), would be switched in the first year.

Under Consolidated's gas sales contract with Northern Natural, dated 24 February 1979, Northern Natural agreed to purchase for the first five years of the contract a daily quantity of 214.5 TJ (200 MMcf at 14.73 psia). For the sixth through tenth contract years inclusive, Northern Natural will purchase quantities decreasing by 20 percent of the original contract quantity each year. The contract contains a take-or-pay clause requiring Northern Natural to take or pay for 85 percent of the annual quantities.

5.8.3.2.2 Conclusions

Should the prebuilt facilities be completed and go into service in 1981 as planned by Foothills, and should no other exports be approved that would occupy capacity in TCPL's system, the Board concludes that no additional facilities would be required to permit this export. However, should the completion of the prebuilt facilities be delayed by any significant period, additional facilities would have to be constructed by the end of 1983 on the Western Section of TransCanada's system if Consolidated quantities were to continue to be moved via TCPL. Under such circumstances, because of the

phase-out feature of the Consolidated exports in the sixth to ninth years, the addition of capacity to handle Consolidated gas should not result in future idled capacity because the decline in exports in the final four years of the proposed exports would be less than the projected rate of increase in demand in Canadian markets.

The Board is satisfied that there are no impediments to the export sale arising from facility, market or contractual matters.

5.8.3.3 Other Matters

5.8.3.3.1 Evidence

In addition to the TCPL and Consolidated cost-benefit study, Consolidated provided its own summary analysis based solely on Consolidated's exports.

The results for the Consolidated export quantities alone were approximated by prorating the results of the combined quantities on the basis of the ratio of the Consolidated proposed export quantities to the total export quantities of TCPL and Consolidated. No attempt was made in the study to separate the individual proposals.

The main result of the Consolidated analysis was that net benefits in the order of \$442 million (present value to mid-1978 in 1978 dollars based on a ten percent discount rate) would accrue to Canada based on the proposed export of $14\,475 \times 10^6 \text{ m}^3$ (511 Bcf).

5.8.3.3.2 Conclusions

In the Board's view, it is inappropriate to allocate the net benefits of Consolidated's proposal simply on the basis of prorating the results of the joint study according to the ratio of the quantities.

The Board finds that the Consolidated export proposal would result in net benefits to Canada of \$631 million (present value in 1978 dollars at a ten percent discount rate) based on the proposed export of $14\,475 \times 10^6 \text{ m}^3$ (511 Bcf). The inclusion of the value of gas by-products and the use of a higher gas export price resulted in the Board's estimate of net benefits being higher than that of Consolidated.

CHAPTER 6

INTERVENTIONS

6.1 Introduction

The Board received 192 interventions with respect to the Licence Phase of the hearing, some of which did not conform with the instructions contained in Order GH-4-79, paragraph 5, with respect to the filing of interventions. Of these, eight did not seek leave of the Board for late filing, and were therefore not considered as a "party" as defined in paragraph 1 of PO-1-GH-4-79. Two intervenors withdrew. Of the 182 interventions that form part of the record of the Licence Phase, 42 provided an expression of views contained either in the intervention, through a witness who gave evidence, or in argument, while the remaining 140, including 130 interventions by producers, were limited to either an expression of support for one or more of the applications or an expression of interest in the proceedings. This chapter contains a summary of the above-mentioned 42 interventions. In Appendix B, a listing of all interventions of record is provided, including, where applicable, an indication of the intervenor's position of support of one or more of the applications.

6.2 Associations

CPA

In its intervention, CPA indicated that a recent update of information on reserves, deliverability and markets upheld its belief that a greater surplus existed than that assessed by the Board in its 1979 Gas Report. CPA stated that this surplus should be exported, as such exports would be of benefit to the Canadian economy. CPA supported this position with a detailed cost-benefit study.

CPA suggested that the Board should approve those applications which provide the greatest benefit to Canada. It added that each application should be assessed on its own merits after all relevant factors have been reviewed and considered. The timeliness of exports, producer netbacks and minimum annual volume obligations were identified as factors needing Board attention.

The cost-benefit study submitted by CPA assessed the costs and benefits of exporting a range of additional volumes of natural gas. Seven cases were examined in which the export volumes ranged from $28\,328 \times 10^6 \text{ m}^3$ (1 Tcf) over five years to $141\,164 \times 10^6 \text{ m}^3$ (5 Tcf) over ten years. Since the

objective of the study was to examine whether exports in general could be justified, none of the cases was based on any particular application before the Board. The results of the analysis were stated in terms of 1980 Canadian dollars.

The basic benefit identified was the revenue from the sale of the natural gas, based on an export price that was assumed to remain constant in real terms at \$2.33/GJ. A second benefit identified was the savings to consumers resulting from lower-priced imported goods. These lower prices resulted from an appreciation in the value of the Canadian dollar because of Canada's enhanced balance of payments position.

The costs assessed in the CPA study included estimates of the costs of producing and replacing the gas, gas transportation costs, and the "opportunity cost" associated with replacing gas exported now.

The "opportunity cost" estimated in the study reflects the fact that, if historically low-cost reserves were committed to the export market rather than held for the existing domestic market, the latter market would have to be supplied with higher cost gas in future years. Thus, domestic supply subsequent to export would be more costly if exports were to take place.

The incremental gas replacement costs used in the study were based on an increasing replacement cost of \$0.005/GJ for each additional 1 055 PJ (1 Tcf) of gas committed for export. This figure was arrived at by plotting historical CPA cost data against cumulative discoveries and visually fitting a line to the data to obtain the replacement cost estimate. The costs that were included were total exploration and development costs for oil and natural gas, exclusive of land costs, with oil and natural gas liquids converted on a heat-content basis. For each export case, the appropriate replacement cost was multiplied by the estimated annual consumption in existing domestic markets starting in 1980 and continuing for 25 years. The cash flows that resulted from each export case were then discounted to obtain the replacement costs used in the study.

The main results of the CPA analysis were that significant net benefits would result from additional exports and that the magnitude of the excess benefits over costs would increase with the volume exported. For example, with total exports of $56\,656 \times 10^6 \text{ m}^3$ (2 Tcf), net benefits of \$2,380 million would occur (present value in 1980 dollars based on a 9.5 percent discount rate).

CPA tested its results at discount rates of 6.5 percent and 12.5 percent. The present value of the resulting net benefits ranged from \$2,570 million to \$2,178 million, respectively.

Board Comments The Board is appreciative of the high calibre of the various analyses found in the interventions, of which the CPA cost-benefit analysis is one example. However, looking at the particulars of the CPA submission, the Board does not share the view that the effect of the estimated increase in the value of the Canadian dollar should be included in a cost-benefit analysis. Because of the complexities and uncertainties surrounding the impact of foreign exchange flows, the Board is reluctant to include foreign exchange benefits or costs of this nature in its analysis.

On the cost side, the Board finds that CPA's specification of relating incremental gas replacement costs to future gas production, with some modifications, is an acceptable approach for approximating these costs. Based on the Board's estimates of future annual gas deliverability and requirements and on the Board's assumptions with respect to future exploration activity and subsequent costs, the Board has also estimated a pattern of change in real resource costs for finding and producing gas in Canada.

While recognizing the high degree of uncertainty in forecasting finding and production costs, the Board has estimated that such real replacement costs may rise approximately one percent for every 1 055 PJ (1 Tcf) produced, from \$0.54/GJ (58 cents/Mcf) in 1979 to \$1.04/GJ (\$1.12/Mcf) in 2000. For comparison with CPA's submission, this is an average increase over the period to 2000 of about \$0.008/GJ for each 1 055 PJ (1 Tcf) produced (0.83 cents/Mcf per Tcf produced), and thus is higher than CPA's estimate of \$0.005/GJ for each 1 055 PJ (0.5 cents/Mcf per Tcf) produced. Given expected annual production, the Board's estimate represents an increase in real average costs of finding and producing natural gas of about three percent per year.

IGUA

IGUA's purpose in intervening was to ensure that any gas exports approved would not jeopardize the long-term supply, deliverability and price of natural gas for Canadian industrial gas users.

IGUA recommended that firm exports should not be permitted beyond 1985 and that within this period first priority should be given to United

States customers now supplied by Canadian gas. In addition, if licences were approved for the export of gas to new markets, IGUA suggested that such licences should face a higher risk of termination after 1985 than those licences that simply extend export deliveries to existing markets.

In determining the priority of the various applications, IGUA recommended that the Board take into account Canadian Government policy regarding energy independence, the need for additional transmission facilities to accommodate the proposed export, and whether such facilities enhance the security of supply to Eastern Canadian markets, including the resultant effect of the additional investments on the delivered cost of gas to Canadian consumers.

IPAC

In its intervention, IPAC expressed concern with regard to the application of the Board's three surplus tests. IPAC contended that the 1979 Gas Report was overly pessimistic in its assessment of future reserves additions, the timing of connection of such reserves, and the deliverability projections of these reserves. IPAC also contended that the Board's estimate of remaining established reserves was low because the Board had been using out-of-date data, and it presented two studies supporting this contention. IPAC stated that it was possible for the Board to approve all the applications with the exception of the requested extensions to existing licences filed by A & S, Canadian-Montana, Niagara, and Westcoast. IPAC believed that these should be considered at what it referred to as a more appropriate time.

It was IPAC's position that the Board, in considering the various applications, should utilize realistic assumptions in applying the surplus tests; should approve applications that provide early sales and that are of sufficient size to maintain exploration and development activity; should consider the needs of each Applicant and its customer; and should consider the likelihood of approval by regulatory authorities in the United States.

6.3 Producers

Amoco

Amoco intervened to express its views on the level of reserves and surplus of gas, particularly with respect to its own situation, and to support substantially increased exports of gas from Canada.

Amoco stated that it believed the greatest economic benefit to Canada and the petroleum industry would result from those projects that encouraged production from established reserves not presently connected to

pipeline transmission systems. Amoco believed this would expand the resource base needed to satisfy future Canadian needs.

Canadian Hunter

Canadian Hunter intervened to express support for the applications of Sulpetro and the Joint Applicants and, in particular, to provide evidence to the Board on the level of reserves ascribed by Canadian Hunter to the Elmworth/Wapiti area.

Chieftain

Chieftain intervened in support of the Joint Application and provided a witness who gave evidence updating Chieftain's gas reserves situation.

Dome

Dome intervened in support of all the applications on the basis that there would be sufficient gas surplus to meet Canadian requirements over the terms of all the applied-for licences. Dome added, however, that, were the Board to determine that the surplus gas available was insufficient to accommodate all export volumes applied for, priority should be given to those exports that would directly support the prebuilding of the southern portions of the ANGTS.

Dome submitted that if an export licence were granted to ProGas, it should commence only on the completion date of the Foothills prebuilt facilities so that TransCanada would not have to expand its pipeline system to accommodate the temporary transportation of the ProGas export volumes.

Gulf

Gulf advocated that natural gas deemed to be surplus to Canadian requirements should be made available to the export market, adding that exports should be viewed as a source of capital necessary to increase the exploration for and development of gas and other indigenous energy sources.

Gulf commented on the Board's three surplus tests, noting that this was the first practical application of the three tests. Gulf provided data on additions to reserves made since the 1978 Gas Inquiry, citing the Hanlan Swan Hills Pool results. Gulf also provided views on connection rates, which it considered to be one of the critical factors in any deliverability forecast. In Gulf's view, the Board was too conservative in this regard in its findings in the 1979 Gas Report. Gulf expressed a similar view with respect to ultimate potential.

HBOG

In its intervention, HBOG noted it had contracted to sell gas to some of the Applicants.

HBOG stated that the Board should assess each application on the basis of the contribution it makes to the Canadian public interest rather than to simply prorate the surplus among all the Applicants. HBOG added that this did not preclude prorationing among applications that provided essentially the same benefits to Canada.

HBOG also recommended that the Board assess the degree of certainty that could be assigned to the realization of predicted public interest benefits, i.e., exports that started early and were of short duration should be given priority over long-term or deferred exports.

Imperial

Imperial intervened to present updated supply and demand projections for natural gas and the resulting supply and demand balance. Imperial estimated that the total primary energy demand in Canada in 1990 would be five percent below the projections it tabled with the Board at the 1978 Gas Inquiry. With respect to oil and gas demand for 1990, Imperial estimated a reduction of ten percent from the projection last tabled with the Board. The revised projections for natural gas demand and potential producibility indicated a larger surplus of producibility than was shown in its last submission. It was Imperial's conclusion that its revised outlook enhanced the feasibility and desirability of additional exports of natural gas surplus to Canadian requirements.

Imperial noted that Esso Resources Canada Limited, a wholly-owned subsidiary of Imperial, had contracted some undeveloped reserves to Pan-Alberta. Imperial therefore expressed support for Pan-Alberta's application.

Norcen

Norcen intervened to present evidence on its own behalf and to submit argument with respect to its interests in the proceedings. Norcen noted that it had committed natural gas reserves to several of the Applicants and thereby had an interest in the Licence Phase.

Norcen recommended priority be given to applications leading to early gas sales and the utilization of existing facilities. In addition, it suggested a classification of licence terms as "before prebuild" and "after prebuild". During the "before prebuild" period, Norcen believed there was

sufficient surplus to permit the Board to grant all applications at full volume. During the "after prebuild" period, Norcen suggested that 70 percent per year be allocated to ProGas and Pan-Alberta, with the remaining 30 percent divided among all of the remaining applications on a prorata basis.

PanCanadian

PanCanadian stated that the applications by ProGas and the Joint Applicants should be favoured as they would provide earliest access to new export markets.

Petro-Canada

In its intervention, Petro-Canada noted that it had unconnected gas reserves in Western Canada in excess of $42\,492 \times 10^6 \text{ m}^3$ (1.5 Tcf), some of which were committed to the Joint Applicants and to Sulpetro.

Petro-Canada also wished to inform the Board of its interests in gas reserves off the East Coast of Canada and of its participation in the Arctic Pilot Project.

Shell

Shell submitted that Canadian consumers should continue to have first priority on available natural gas supplies wherever gas was economic or gas service was determined to be in the national interest. Shell believed that as a result of industry activity and possible changes in the method of forecasting deliverability, supplies of gas in Canada were somewhat higher than indicated in the Board's 1979 Gas Report. Shell's intervention updated its forecast of natural gas supply and requirements presented to the 1978 Gas Inquiry.

6.4 United States Customers

Great Lakes

Great Lakes stated it had intervened because it was in the process of negotiating contracts for the transportation of additional volumes of gas to be exported by Consolidated and ProGas.

Michigan Wisconsin

Michigan Wisconsin intervened in support of the TransCanada application to extend Licence GL-1 and the ProGas application. Michigan Wisconsin buys gas from Midwestern exported under Licence GL-1 and also has contracted to purchase volumes proposed for export by ProGas.

Midwestern Customer Group

The Midwestern Customer Group is composed of municipally and investor-owned gas distribution utilities serving customers on Midwestern's Northern System in North Dakota, Minnesota, and Wisconsin.

The Midwestern Customer Group intervened on behalf of the Joint Applicants, having particular interest in the proposed extension to Licence GL-1 because of its members' dependency on this licence for their gas supply. The Midwestern Customer Group recommended that Licence GL-1 be extended to 14 December 1985 and beyond to 1995 at increased daily volumes in order to meet the growth in requirements of its members.

Midwestern

Midwestern intervened in support of the application by TransCanada to extend Licence GL-1. Midwestern indicated that 60 percent of its supply requirements for its Northern System is provided through GL-1, and any cessation of these volumes would result in interruptions to priority-one customers on the Northern System. Midwestern recommended that priority be given to supplying existing export customers such as Midwestern and noted that exports under Licence GL-1 could continue without requiring additional facilities. Further, Midwestern suggested that the licence term for GL-1 be extended beyond that applied for.

Minnesota PSC

Minnesota PSC intervened in support of TransCanada's application to extend Licence GL-1. Minnesota PSC noted the dependency of Midwestern's Northern System and particularly the dependency of the full-requirement communities. Minnesota PSC recommended that priority in allocating volumes be given to existing export customers relying solely on Canadian supply.

Natural Gas Pipe

In its intervention, Natural Gas Pipe noted that it had contracted to purchase gas from ProGas and that it supported that application.

Northern Natural

Northern Natural intervened in support of the Joint Application. Northern Natural and Consolidated have entered into a gas sales contract for the volumes Consolidated has applied to export. A subsidiary of Northern Natural would be the operator of Northern Border, as part of the ANGTS.

North Dakota PSC

North Dakota PSC intervened on behalf of the application by TransCanada to extend Licence GL-1. It noted Midwestern's dependency on Canadian gas supply for its Northern System and the dependency of certain full-requirements communities in North Dakota on Canadian gas supplies. North Dakota PSC recommended that priority be given to existing export customers.

Northwest Alaskan

Northwest Alaskan intervened on behalf of the Joint Application. Northwest Alaskan has contracted with Pan-Alberta for the purchase of volumes of gas to be exported to the United States through the prebuilt sections of the ANGTS.

Pacific Interstate

Pacific Interstate intervened on behalf of the Joint Applicants. Pacific Interstate would purchase natural gas exported by Pan-Alberta through the western leg of the Foothills system.

Tennessee

Tennessee intervened in support of the ProGas application, stating that it had entered into a contract with ProGas to purchase some of the proposed ProGas exports.

Texas Eastern

Texas Eastern intervened in support of the ProGas application, noting that it had entered into a contract with ProGas to buy a portion of its proposed exports.

6.5 Other CompaniesAGTL

AGTL stated that as it was a major shareholder in Pan-Alberta and was the sole shareholder of Q & M Pipe Lines Ltd, it supported the Joint Application.

B.C. Hydro

B.C. Hydro, a major supplier of natural gas to consumers in the lower mainland and of butane-air to consumers on Vancouver Island, intervened to express its concern for the long-term supply of natural gas at just and reasonable prices. In its intervention, B.C. Hydro also expressed concern that the Board had made no provision in its estimate of

domestic requirements for natural gas service to Vancouver Island, a project currently under serious consideration.

In addition, B.C. Hydro was concerned about the impact on Westcoast's facilities of the proposed Columbia Gas export. B.C. Hydro also expressed concern about the serious effect that the loss of Westcoast's export market might have on operating expenses to the detriment of Canadian consumers.

Consumers'

Consumers' supported the export application filed by its subsidiary, Niagara, and indicated its support for exports in general to the extent that approval of such exports would not jeopardize Canada's long-term supply requirements. Consumers' stated that it also wished to express its concern regarding TransCanada's proposed "backstopping" diversion of gas to Northern Border and the effect this would have on transportation costs in general and on the security of supply to Eastern Canadian markets.

Consumers' recommended the adoption of three categories of export markets. In descending priority they were: those entirely dependent upon Canadian gas; those currently served by but not dependent upon Canadian gas; and those considered to be new markets.

Gaz Métropolitain

Gaz Métropolitain stated its objective was to assure itself of the availability and security of long-term natural gas supplies in order to meet the increasing requirements of its market. While supporting in principle the view that the granting of export licences might encourage further exploration and development of natural gas reserves, Gaz Métropolitain stated that no export licence should be granted or renewed unless current and future Canadian requirements were satisfied, including those of expansion markets, and that any new licences should be conditioned to ensure that the quality of present and future service to Canadian distributors was guaranteed.

Inland

Inland wished to express to the Board its concern regarding the availability of natural gas supplies for its system. Inland stated that it supported approval of the export applications filed by Westcoast subject to assurance being given that Canadian consumers would have first priority in the event of a shortfall in supply on the Westcoast system.

IPSCO

IPSCO intervened on behalf of the Joint Applicants. It indicated that its interest lay in the large-diameter steel pipe requirements that would result from the construction of the prebuild portion of the ANGTS. In addition, IPSCO pointed out the positive effect that exports through the prebuilt facilities would have on the Canadian steel and pipe industry and specifically on IPSCO.

Kingston PUC

Kingston PUC noted that the Board's 1979 Gas Report assumed the increase in demand for natural gas to be three percent per year until 1992. It was the view of Kingston PUC that recent increases in world oil prices could lead to greater increases in gas demand than the Board had provided for. With respect to its own sales area, Kingston PUC expected that increased demand would result in sales at the end of 1980 that were some 19 percent higher than 1978 levels. It submitted that as a result, exports of gas should be determined on the basis of a surplus calculation that would take into account the probability of a reduction in offshore oil supplies in the period 1979-92, a reduction that could increase Canadian domestic gas demand.

Union

Union noted in its intervention that it served a market area of some 2.4 million people and that Union depended upon TransCanada for approximately 95 percent of its gas supply.

Union submitted that the availability of an adequate supply of gas for the future needs of its franchise area, the price of the gas, and, in consequence, the demand for gas, might be affected by the Board's decision.

Union also submitted that the Board should consider the cost of SNG produced in Canada, advocating that if additional gas exports were authorized, the price of such gas exports should be sufficient to permit recovery of the higher cost of producing SNG.

Union expressed the opinion that the Board should not deviate from the findings of the Board's 1979 Gas Report despite new evidence filed by the Applicants. Union felt that to do so would reduce the value of future natural gas inquiries causing the participants to question the time and effort expended in their participation.

Union stated that gas exports should be approved only after the Board has determined the existence of an exportable surplus and has found such exports to be in the public interest. Union explained that such public interest matters should include consideration of the use of gas in making Canadian industry more competitive in world markets and the use of gas in reducing Canadian oil imports.

6.6 Public Interest Groups And Others

CARC

CARC's intervention took issue with the arguments presented by the Joint Applicants in support of their export application: namely, that export revenues would double reserves additions, that prebuilding would make the ANGTS economically viable, and that Canadian interests were best served by completing the ANGTS as soon as possible.

CARC recommended that any new exports approved should be short-term, should assist in the expansion of new Canadian markets, and should not in any way jeopardize domestic requirements nor precipitate the need for frontier gas. CARC added that exports should maximize revenues for gas producers in order to encourage further exploration. Finally, CARC recommended that approval of exports tied to prebuilt facilities should only be given after the sponsors of the project had proved to the Board's satisfaction the financeability of the entire ANGTS.

NDP

In a letter to the Board, Mr. Cyril Symes, M.P., on behalf of the New Democratic Party, expressed the NDP's opposition to any additional gas exports at this time.

6.7 Provincial Governments

British Columbia

British Columbia intervened with reference to the applications of Westcoast, Columbia Gas, and Pan-Alberta on the basis that the exports applied for could have a direct bearing on the level of gas production in the Province.

The intervention noted that British Columbia's policy was to encourage short-term exports of surplus gas to the extent that such exports would ensure the maintenance of a healthy oil and gas industry.

The intervention stated that British Columbia was concerned that local production and export revenues were highly susceptible to fluctuations

in demand in the area served by Northwest, that out-of-province production exported through the facilities of Westcoast be assigned an equitable share of Westcoast's cost of service, and that such out-of-province production not displace British Columbia production. British Columbia therefore supported the applications contingent upon the existence of a suitable export price structure. British Columbia reiterated its position, however, that any alteration to Westcoast's Licence GL-41 must be preceded by the acceptance by Northwest of a contractual obligation to take an acceptable minimum annual volume.

Concerning extension of gas service to Vancouver Island, British Columbia is convinced that such an extension, which is currently under consideration, would benefit both the Province and Canada.

Manitoba

Manitoba submitted that it had an interest in ensuring that the long-term requirements of domestic consumers should not be jeopardized by the granting of new natural gas exports.

The intervention expressed concern with respect to the time-frame of the Board's deliverability tests, protection periods, and the terms of proposed export applications. In addition, Manitoba was also concerned about the uncertainty of estimates of supply and requirements in light of changing world prices and interfuel substitution.

Manitoba presented for Board consideration a study of the benefits and costs of further gas exports. The study assessed the benefits and costs of additional exports of $70.8 \times 10^9 \text{ m}^3$ (2.5 Tcf) of natural gas over the period 1980 to 1986 as compared with the benefits and costs of alternative Canadian consumption of this gas over the period 1991-98. The proposed volumes would be transported on the AGTL and TCPL systems.

Manitoba based its cost-benefit analysis on what it believed to be a more reasonable set of assumptions than those adopted by the Applicants.

For example, Manitoba assumed in its study that natural gas prices would increase substantially in real terms to the year 2000. Unlike Pan-Alberta, Manitoba did not incorporate in its analysis benefits from induced exploration effects as they were considered inappropriate in a cost-benefit framework.

Manitoba expressed the view that the use of high real rates of discount averaging ten percent might not be an appropriate measure of the marginal social "opportunity costs" of the proposed exports. Consequently, the Manitoba study used real discount rates of two, four, and six percent.

Finally, in order to make provision for the risk incurred with respect to protecting future Canadian gas requirements if exports were undertaken, Manitoba proposed a simple methodology involving differing discount rates to reflect an added risk premium.

Benefits included the export value of the natural gas and the value of by-products associated with the production of the gas. The export price was assumed to increase in real terms from \$2.39/GJ in 1979 to \$5.01/GJ in 2000. This represents a 3.6 percent annual growth rate. The value of by-products was assumed to be 30 percent of the value of the export sales.

The costs included estimates of the producers' costs, the transportation costs, and the "opportunity cost" of exporting the proposed volumes.

In estimating the "opportunity cost" associated with the export volumes, the benefits of alternative domestic gas consumption were assumed to equal the export value of the gas (reflecting the "opportunity cost" of the gas) and the value of by-products as defined earlier. The producers' cost and the AGTL transportation costs were assumed to be the same as in the export case. Transportation costs on the TCPL system were assumed to consist of pipeline operating and maintenance costs. Additional capital costs were not attributed to transporting the gas.

The major result of the Manitoba analysis was that net negative benefits (i.e., costs) of approximately \$56.4 million (present value in 1978 dollars based on a four percent discount rate) would occur based on the export of $70\,820 \times 10^3 \text{ m}^3$ (2.5 Tcf). Thus, Manitoba estimated in their "middle case" that the present value of the net benefits of additional natural gas exports would be \$56.4 million below the benefits of retaining the gas to meet future Canadian requirements.

Manitoba tested these results at discount rates of two percent and six percent. The present value of net benefits ranged from -\$1,788 million to +\$1,081 million, respectively.

Board Comments The Board appreciates the extensive evidence put forward by Manitoba in its cost-benefit analysis. However, the Board views the major assumptions used by Manitoba for its "middle case" as being more appropriate to a "worst possible case". Manitoba's assumptions were:

that real gas prices would increase at an annual rate of some 3.6 percent; that the appropriate discount rate was 4 percent; and that export deliverability could be deferred to be called upon at the same rate in the future. These assumptions, taken separately, appear to be pessimistic vis-a-vis current exports and, when combined, are not viewed by the Board as reasonable for a "middle case". Also, it may be noted that deliverability cannot be deferred as assumed.

In assessing the alternative to exporting gas now, Manitoba assumed that gas production could be deferred for eleven years and then used domestically at essentially the same rate. The Board notes that the effect of assuming that deliverability can be deferred and then be called upon for future Canadian use at the same rate as in the export proposals is to overstate the value of the alternative use and, as a result, underestimate the net benefits of exporting gas.

Also, Manitoba valued the gas at an estimated export price that was increasing in real terms at an average annual rate of 3.6 percent. In the Board's view, the effect of the price and cost assumptions is to overstate the value of the alternative to exporting and thereby underestimate the net benefits of exporting gas.

Finally, the Manitoba study used real discount rates in its analysis that in combination with its other assumptions result in increasing the value of an alternative use relative to the export proposal. In its own analysis, the Board uses a range of 5 to 15 percent for discount rates and normally relies on a 10 percent value.

Nova Scotia

Nova Scotia submitted that before export licences are granted priority should be given to potential demands in regions isolated from domestic supply. Thus, in its view the present surplus test should include requirements for both the Quebec expansion and Maritime markets. In addition, Nova Scotia suggested that exports should be allowed to facilitate the expansion of the existing gas transmission system, and should be priced at whatever the market would bear.

Ontario

Ontario requested the Board to assess the appropriateness of exporting relatively low-cost natural gas when in a few years supplementary supplies might be needed from the frontier areas at significantly higher

cost. In addition, Ontario urged the Board, in making its decision, to be guided by those proposals that would result in the optimum benefits to Canada and in particular to the Canadian consumer. Ontario suggested that, in determining those benefits, the Board should take into consideration the impact of exports on the Canadian economy, on the cash flow to producers, on the delivery of frontier gas, and on the construction of facilities for eventual use by Canadians.

Quebec

Quebec intervened to remind the Board of the Province's stated objectives to have gas serve 12 percent of the Province's energy market by 1990. Quebec urged the Board to stand by its findings contained in the 1979 Gas Report in determining an exportable surplus. Specifically, Quebec referred to the Board's estimate of net sales of natural gas for Quebec, including gas expansion.

Saskatchewan

Saskatchewan stated that, because it was unable to become self-sufficient in natural gas, it was affected by decisions concerning additional exports and was concerned that any applications which are approved should maximize the net economic and social benefits for Canadians, including residents of Saskatchewan.

CHAPTER 7Reasons for Decision7.1 Introduction

In the foregoing chapters, evidence has been summarized and a number of conclusions have been reached on specific matters. This chapter outlines the Board's general observations and conclusions and identifies the reasons for decision pertaining to the disposition of each application.

Section 81 of the National Energy Board Act states that except as provided for in the regulations, no person shall export gas except under the authority of and in accordance with a licence. Consequently, under Section 82 of the Act the Board may, subject to the regulations, issue an export licence with such terms and conditions as are prescribed by the regulations. Pursuant to the Part VI Regulations of the National Energy Board Act, all natural gas export licences are subject to the approval of the Governor in Council.

Section 83 of the Act provides that:

"Upon an application for a licence the Board shall have regard to all considerations that appear to it to be relevant and, without limiting the generality of the foregoing, the Board shall satisfy itself that:

- (a) the quantity of gas... to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard, in the case of an application to export gas, to the trends in the discovery of gas in Canada; and
- (b) the price to be charged by the applicant for gas... exported by him is just and reasonable in relation to the public interest."

Table 7.1 shows the term quantities of gas and the number of years term of the licences being applied for by each Applicant.

7.2 General Issues7.2.1 Exports and the Public Interest

The particular nature of the regulatory process, where various parties are brought together in the forum of a public hearing to support or oppose a given project or proposal, usually gives rise to the airing of a wide variety of issues that must be taken into account in the

Table 7.1
SUMMARY OF EXPORT APPLICATIONS

	<u>Term Volume</u>		<u>Term</u>	
	<u>10^6 m^3</u>	<u>PJ</u>	<u>Bcf</u>	<u>(No. of years)</u>
Alberta and Southern	20 674	801.3	729.8	up to 4
Canadian-Montana (two applications)	5 887	223.4	207.8	up to 8
Columbia	5 779	225.0	204.0	15
Niagara	3 300	124.9	116.5	16
ProGas	21 600	817.8	767.0	9
Sulpetro	1 870	70.8	66.0	3
Westcoast (three applications)	24 077	937.6	850.0	up to 8
Joint Application				
Consolidated	14 475	548.0	511.0	9
Pan-Alberta	139 880	5 462.3	4,937.9	14
TransCanada	11 331	429.0	400.0	5
 TOTAL	 248 873	 9 640.1	 8,790.0	

decision-making process. This is no less the case in a public hearing dealing with applications to export natural gas, where the Board must not only consider certain specified issues such as those itemized in the National Energy Board Part VI Regulations, but also must consider those topical matters which, in its perception, are pertinent to the decision. The underlying theme of the latter is whether it is in the public interest to approve any new exports.

One issue that was discussed extensively during the Hearing can be paraphrased as follows: "to protect Canadian domestic requirements it is necessary to export gas so that industry keeps exploring, and thus finds the natural gas that Canada will require in the future."

The argument underlying this apparent paradox, that exports would enhance domestic supply, is that should additional exports not be allowed, then industry activity would be curtailed and the quantities of future natural gas discoveries would decline. This was said to result because a lack of marketing prospects for any natural gas found, which would lead to delays before production, would reduce the profit incentive for those in the exploration business. Thereafter, should Canadian requirements need additional natural gas supply it might not be easy to get the exploration sector of the industry geared up again.

Furthermore, it was argued that a high level of industry activity would result in healthy competition that would engender the advancement of petroleum technology, and might indeed result in the finding of gas that under less competitive conditions would not be found. Other arguments contended that the greater the exploration activity the more knowledge would be gained about the resource base in Canada, which in turn would facilitate the planning of appropriate energy policies. The positive impacts of a high level of industry activity on the overall Canadian economy were also stressed. Finally, it was argued that not exporting surplus gas now might result in retaining gas in Canada that would become obsolete for most purposes, because alternative forms of energy, such as photoelectric cells, might be developed to replace hydrocarbon energy.

Another facet of the argument stressed that circumstances over the past decade had changed considerably from optimism about natural gas supply, to concern about possible gas shortages in Canada, followed by a return to today's optimistic predictions of Canadian gas supply prospects. Thus, given that natural gas is regarded as a finite nonrenewable resource, the value of which has increased dramatically in recent years, it was argued that it would be imprudent to expect that the high finding rates of the last few years would continue indefinitely.

In essence, the amount of exploration and delineation that will take place in Canada for natural gas is dependent upon industry's perception of the likely profitability of these activities. Expected profitability depends upon many factors including perceived geological prospects, anticipated natural gas prices, natural gas production costs

including taxes and royalties, the expected cost of exploratory activity, and expected delays that may be encountered either before a discovery is put into production or, if after commencing production, in production rates themselves.

Closely related to such expectations is industry's concern with adequate cash flow, particularly where cash flow is needed by the many smaller companies in lieu of equity risk capital. The Board recognizes that industry cannot be expected to uneconomically stockpile excessive delineated reserves. Should such a burden be thrust upon private industry, the Board believes that exploration activity would slow down perceptibly.

The Board has established surplus tests to regulate exports with a view to protecting Canadian consumers for a reasonable period into the future, and the Board views such tests as establishing a proper reserve of natural gas to be held in stock by the industry. The Board believes that this level of reserves retention is not viewed by the industry as an undue burden and that an appropriate rate of exploration and development will be maintained.

Although the main thrust of the Board's three surplus tests is the protection of Canadian gas consumers, the tests also serve to encourage the industry to maintain exploration, development, and deliverability of natural gas. The surplus tests are not used by the Board in isolation. In the present Hearing, the Board requested certain Applicants to file estimates of net economic benefits that might result from additional natural gas exports. Those Applicants and a number of intervenors filed cost-benefit studies; similarly, the Board has undertaken cost-benefit analyses of the various export proposals. Through the use of cost-benefit analysis, the Board further protects the public interest by requiring that Applicants clearly show, under various forecast conditions of energy prices and costs, that an export will yield positive net economic benefits to Canada.

Another factor that must be considered relative to the overall public interest was raised by Ontario. Ontario suggested that supplies of natural gas to be exported must be determined in light of Canada's overall energy situation, not just in the narrow context of the natural gas

industry. CARC advocated that the Board exercise caution in the approval of additional natural gas exports so as not to preclude the government from future energy policy options.

The Board is aware that a decision with respect to additional natural gas exports must take into account Canada's overall energy situation. In particular, the Board recognizes that the present energy circumstances are largely determined by world oil supply and prices. In all aspects of the Board's analysis, it considers total energy, either explicitly, through direct consideration of the inter-energy competition in the Board's gas demand forecast, or implicitly, through the inclusion of relative prices, the cost of capital devoted to energy projects, and exploration costs in the Board's gas supply studies.

In considering the Canadian public interest, the Board is acutely aware of today's kaleidoscopic energy situation. However, the Board does not believe that natural gas, which is used directly or indirectly by most Canadians, will become obsolete as a fuel within the forecast period to the end of the century, or indeed well into the next century. In considering the pros and cons of exporting additional gas in the near future, the Board seeks to ensure that advantages to Canada outweigh risks before recommending the issuance of export licences. In particular, the Board believes that its present approach, in which firm exports are limited to a short period, is consonant with the uncertainties surrounding energy supplies and prices.

7.2.2 Economic Impact

It is the Board's view that the likely macroeconomic impacts resulting from any of the export proposals could be absorbed by the Canadian economy without undue problems. The Board finds that the overall impact of additional gas exports will be beneficial, although the estimated improvement in the current account balance appears to have been overstated by several Applicants and intervenors whose analysis did not fully take into account the effects arising from any resulting appreciation in the value of the Canadian dollar. In this regard, the Board does not share the view that an increase in the value of the Canadian dollar is necessarily a beneficial effect. An appreciation of

the dollar, while tending to moderate any increase in inflation or rise in interest rates, also means higher export prices and a reduction in the amount of exports of other commodities.

The Board has not undertaken its own estimate of the macroeconomic impact of each export proposal because, on the macroeconomic level and under forecast economic conditions, the impacts are relatively small. For the export applications considered in this Hearing, social cost-benefit analysis provides a more appropriate measure for comparing the competing applications.

7.2.3 Applicants' Supply

Although the Board must satisfy itself that the total quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard, in the case of an application to export gas, to the trends in the discovery of gas in Canada; it believes that, in considering the merits of individual applications, it must have regard for the evidence with respect to an applicant's supply and the commitment of that supply to serve the various requirements the applicant is obligated to fulfill. Accordingly, in determining the volume and term of such export licences as the Board may be prepared to issue, the Board has taken into account the level of gas supply that it has found the applicants have available to dedicate to new exports.

7.2.4 The United States Regulatory Situation

The import of natural gas into the United States is subject to the approval of two regulatory agencies, ERA and FERC. All matters concerning prices and the public interest or "need" to import are dealt with by ERA⁽¹⁾, while all other regulatory matters fall under the jurisdiction of FERC.

TransCanada advised that no further U.S. regulatory approval was required for the proposed extension of exports under Licence GL-1. Three of the applicants, Alberta & Southern, Canadian-Montana, and Niagara, indicated that their customers have yet to file applications with ERA and FERC for the import of natural gas from Canada. A conditional approval

(1) Except for imports directly related to the ANGTS.

was granted in June 1978 to Northwest Alaskan gas by FERC to import Pan-Alberta gas. Although the United States customers of Sulpetro have filed applications with ERA and FERC to import gas, they have yet to conclude a transportation agreement with Tennessee and Consolidated Natural Gas Corporation. Therefore, a final decision on importing natural gas is still awaited. In general, most of the Applicants stated that their customers would seek approval from United States regulatory agencies after they had obtained permission to export gas from Canada.

One interrelated issue on which some parties testified pertained to the pricing of Canadian natural gas in the United States. Under the yet-to-be-adopted incremental pricing provisions of the Natural Gas Policy Act of 1978, natural gas imported into the United States and contracted for on or before 1 May 1978 would, under certain conditions, be subject to rolled-in pricing; those natural gas imports contracted after 1 May 1978 would be subject to incremental pricing. In the latter case, there could be marketing problems if a particular gas export were subject to incremental pricing provisions and if the sale were not subject to a take-or-pay condition. In such circumstances, it is possible that the gas would be drawn upon only after other supplies available to the purchaser on a rolled-in basis could not meet demand. In other words, the Canadian export could become a peaking service. As the mechanics and applicability of incremental pricing are being widely debated in the United States in both government and industry, it would be premature for the Board to draw final conclusions on the effect of incremental pricing on a particular export proposal. It may, however, be a matter the Board will wish to take into account in the future.

Some of the parties to the Hearing stated that, in their opinion, United States authorities would approve only those gas import applications that supported ANGTS. The Board does not believe it appropriate, however, in considering applications before it, to speculate on their subsequent treatment by other tribunals.

Accordingly, while it is necessary that the Board, Canadian industry, and the Canadian Government understand United States policies as they apply to the import of Canadian gas, the Board holds the view that it

would be inappropriate to prejudge how those policies would affect individual applications before it. The Board must assess the relative merits of an export application in light of the Canadian public interest; United States authorities will consider an import from the viewpoint of United States public interest.

7.2.5 The Prebuilt Facilities of Foothills

7.2.5.1 Background

The Pan-Alberta application is directly tied to the proposal to prebuild certain southern segments of the ANGTS. The shipment of Canadian gas through the prebuilt sections would allow for the earlier entry into service of those segments, allowing among other things for their earlier depreciation. Proponents of the pipeline have advocated that prebuilding will assist in the financeability of the whole system.

The concept of prebuilding was first mentioned by the Board in its Northern Pipelines Report. The Board noted that there was surplus producibility of natural gas in Alberta that, if it could be sold and delivered, would encourage exploration and development in that province, thereby lifting the level of the deliverability over what it would otherwise be in the late 1980's. Assuming that Alaskan gas was to be connected to markets by a natural gas pipeline through Canada, the Board stated that "... it could be possible to prebuild some of the southern Canada and northern United States pipeline capacity to market gas which may be surplus to Canada's requirements in the late 1970's and early 1980's".

Subsequent to the release of the Northern Pipelines Report, the Governments of Canada and the United States entered into an agreement on principles applicable to building a natural gas pipeline for the transportation of natural gas from Alaska across Canada. Paragraph 4(a) of the agreement contained specific requirements for financing of the pipeline:

"It is understood that the construction of the Pipeline will be privately financed. Both Governments recognize that the companies owning the Pipeline in each country will have to demonstrate to the satisfaction of the United States or the

Canadian Government, as applicable, that protections against risks of non-completion and interruption are on a basis acceptable to that Government before proof of financing is established and construction allowed to begin."

The Government of Canada subsequently enacted The Northern Pipeline Act to inter alia carry out and give effect to the agreement. Under Section 20 of that Act, a certificate of public convenience and necessity was declared to be issued in respect of the Canadian portion of the pipeline.

Schedule III to The Northern Pipeline Act laid down terms and conditions applicable to the certificate issued to Foothills. Condition 12 thereof set out specific requirements with respect to financing:

"The Company shall, before the commencement of construction...

(b) establish to the satisfaction of the Minister and the Board that

(i) financing has been obtained for the pipeline, and

(ii) protection has been obtained against risk of non-completion of the pipeline and interruption of construction on a basis acceptable to the Minister and the Board."

7.2.5.2 Benefits of Prebuilding

Pan-Alberta testified that prebuilding was important to the realization of the entire ANGTS, would bring about a number of economic benefits to Canada, and would help in the assembly of the manpower and equipment required for the whole project, thus fostering the establishment of the whole infrastructure required to build the pipeline. Pan-Alberta stated that prebuilding would be an important first step in the building of the ANGTS, and would give momentum to the whole project that, among other things, would permit the connection of northern gas reserves to the Canadian market. Most particularly, however, the impact of prebuilding on the financing of the whole pipeline was emphasized. It was stated that cash flow generated from the prebuilt facilities would help finance the remaining portion of the project and that investors would have greater confidence in the whole project if the prebuilt facilities were in place. As described elsewhere in this report, Pan-Alberta also asserted that

prebuilding and exporting gas through such facilities would have a number of economic benefits to Canada.

7.2.5.3 Financing and Construction Plan

Foothills testified that it would meet the legal requirement of the Northern Pipeline Act and demonstrate the financeability of the pipeline before the commencement of construction of the prebuilt facilities. Foothills planned to commence construction of the western leg in June 1980 and put it into service by 1 November 1980. The construction on the eastern leg would commence in June 1981 and be put into service by 1 November 1981.

Northwest Alaskan testified that the Northern Border prebuilt facilities would be financed on a "stand alone" basis, and that Northern Border expects to obtain a certificate from FERC by the end of 1979. If the Pan-Alberta exports were approved, Northern Border would commence construction in 1980 to have the pipeline completed in the fall of 1981.

Foothills stated that the ANGTS would be built regardless of whether prebuilding proceeds, and that the target date for delivery of Alaskan gas with or without prebuilding is the fall of 1984.

7.2.5.4 Views of the Board

The construction and entry into service of the Foothills pipeline, as part of the whole ANGTS, have already been found to be in the public interest, and by virtue of the Northern Pipeline Act a certificate of public convenience and necessity has been issued to Foothills.

The Board believes that, to the extent prebuilding would contribute to the financing and completion of the whole project, prebuilding would also be in the public interest. Accordingly, the Board is prepared to recommend the issuance of licences that would foster prebuilding of the southern sections of the Foothills system. However, while the dedication of export volumes for the prebuilt facilities will give a significant boost to the entire project, the need for the continuation of exports of Canadian gas through the Foothills system, after Alaskan gas begins to flow, appears to be questionable.

The Board does not accept Pan-Alberta's contention that early "best-efforts" exports by Pan-Alberta through the TCPL system would contribute to the prebuilding or financing of Foothills. The Board will therefore recommend that any licence issued to Pan-Alberta be conditioned so that it will authorize the export through the prebuilt facilities of Foothills only.

Whereas the Board is currently holding separate hearings respecting tariffs and tolls to be charged by Foothills, the financing of the pipeline, and other related matters, certain related issues are germane to the consideration of Pan-Alberta's export application with respect to the determination of the export price. The evidence shows that the capacity of the prebuilt facilities would be significantly greater than required to move the export volumes applied for, resulting in a higher unit cost of service before Alaskan gas begins to flow. It is the Board's view that to the extent that the Canadian gas volume is less than the capacity of the prebuilt facilities, the resultant higher cost of service should not be borne by Canadians.

7.2.6 The Export Price

Section 83(b) of the National Energy Board Act requires that the Board satisfy itself that the price to be charged by an Applicant for gas exported by him is just and reasonable in relation to the public interest.

Before 1 October 1974, the Board reviewed the level of the contract price as part of proceedings considering new export applications. Gas exported under licences was priced on an individual basis, with the price determined by the provisions of the gas sales contract applicable to each licence. In its 1967 Westcoast decision, it enunciated the following three tests for price measurement:

- "1. the export price must recover its appropriate share of the costs incurred;
2. the export price should, under normal circumstances, not be less than the price to Canadians for similar deliveries in the same area; and
3. the export price of gas should not result in prices in the United States market area materially less than the least cost alternative for energy from indigenous sources."

In 1974, under the provisions of Section 11A of the National Energy Board Part VI Regulations, the Board held a public hearing into the level of gas export prices then prevailing, and subsequently recommended to the Governor in Council that a new price be established. On 1 October 1974, the Board implemented the decision of the Governor in Council by amending all export licences to provide, with one exception,⁽¹⁾ for a new export price to be effective on 1 January 1975. Since that date, the Board has made periodic reviews of the export price that have resulted in an orderly increase in the gas export price to current levels.

With respect to the applications to export gas that are the subject of this proceeding, the Board is satisfied that the requirements of Section 83(b) would be met if those gas exports were priced at the prevailing export price, where those exports would be made under circumstances similar to current exports under existing licences. The Board is aware, however, that special circumstances may arise with individual exports for which special consideration may be necessary. The Board continues to keep the level of export prices under review.

7.2.7 Term of Licences

The applications before the Board request export licences of unprecedented variety and complexity. They reflect the differing expectations and perceptions of the industry of how the Board's new surplus tests, as set out in the 1979 Gas Report, might apply to the various export plans. The requests of the export Applicants ranged from short-term new licences to long-term new licences, from extensions to existing licences that would commence in the near future to extensions to existing licences that would not begin for ten years, and from firm licences to conditional licences.

The three tests used to determine whether a quantity of gas proposed to be exported is surplus to reasonably foreseeable requirements for use in Canada are described in detail on pages 95 and 96 of the 1979 Gas Report. In brief, the three tests provided for the following:

(1) For Licence GL-41, the new price was made effective 1 November 1974.

1. Current Deliverability Test: The applicant must demonstrate a surplus of annual deliverability from established reserves in excess of the sum of total annual Canadian requirements and authorized exports for a minimum period of highly assured protection.
2. Current Reserves Test: The applicant must demonstrate that a surplus exists in the quantities of established reserves which remain after setting aside 25 times the first year's Canadian demand, plus authorized exports.
3. Future Deliverability Test: The applicant must demonstrate that forecast deliverability from established reserves, reserves additions, and, when appropriate, new sources such as frontier gas, will exceed expected, or forecast, Canadian demand plus authorized exports for a reasonably foreseeable period.

With respect to the Current Deliverability Test, the Board concluded that the period of highly assured protection should be a minimum of five years, while for the period of future deliverability protection, the Board concluded it should be approximately ten years.

The Board noted, however, that because of the nature of the new protection procedure it was not possible to state a specific quantity of gas that was surplus to the reasonably foreseeable Canadian requirements under all circumstances. It believed that it would be necessary to apply all three tests to determine if a proposed export volume were surplus. It also stated that it might be in the public interest to grant, from time to time, longer term licences that would include deliverability from trend gas for such purposes as making a new project, such as a major transmission system, economically viable.

In short, there is no quick, easy measure against which an export application can be assessed. In general, the Board will restrict licences to those that can meet the requirements of the Current Deliverability Test and the Current Reserves Test, and will therefore favour approval of licences that terminate within the limits of the period for which highly assured protection can be demonstrated. However, the Board recognizes that from time to time special circumstances will argue for longer term licences, but these would be the exception, not the rule.

In the past, gas exports have been authorized for periods as long as 25 years. One justification for the longer term of at least some

earlier export authorizations was the relationship between the proposed export and the construction of new pipeline facilities that were required, at least in part, to transport the exported volumes. In those circumstances, a longer initial term was considered appropriate to enable the project to be financed and to ensure that there would be adequate deliveries for a sufficient period to allow the cost of the pipeline to be recovered. In the present circumstances, only the exports tied to the prebuilding of southern sections of the Foothills pipeline⁽¹⁾ involve the construction of major new facilities, and these of course will be underpinned for the greatest portion of their economic life by the transmission of Alaskan gas.

Accordingly, the Board's recommendations arising from this hearing will be for the approval of export licences with terms no longer than that provided by the Current Deliverability Test. This will have the effect of limiting the term of licences to be issued to the various Applicants to no more than seven or eight years.

With respect to extensions of existing licences, the Board noted on page 96 of the 1979 Gas Report that it did not assume, in assessing surplus, that there would be some form of automatic extension of existing licences. Rather, the Board advised licensees who wished to export natural gas beyond the terms of their present licences that they must apply for authorizations in the same manner as any other applicants for licences. In this regard, the Board does not believe that it is appropriate to consider too far in advance the extension of licences that do not expire until some years in the future, unless there are compelling reasons to the contrary.

7.2.8 Pipeline Facilities

The Board recognizes that approval of certain of the applications to export gas will have a direct impact on existing pipeline systems and will in some cases necessitate earlier expansion of pipelines

(1) The relationship of Pan-Alberta's proposed exports to the Foothills proposal is discussed in section 7.2.5 of this report, specifically in sub-section 7.2.5.4. The extent to which approval of other export applications entail additional facilities on existing systems is discussed in section 7.2.8.

than would otherwise take place. In particular, the export proposals of Niagara, ProGas, Sulpetro, Consolidated, and TransCanada all involve using the TransCanada system, and it appeared to the Board that approval of additional export volumes would require an expansion of the TCPL system. Accordingly, the Board concluded that it should examine the impact of various combinations of export approvals on Canadian pipeline systems, and in particular on TransCanada, from the perspective of pipeline expansion that will be required in the future to serve Canadian markets as natural gas requirements in those markets grow. Furthermore, the Board was concerned whether an earlier expansion of those pipeline systems, induced by export approvals now, would contribute to the public interest or result in the creation of unnecessary surplus capacity when exports terminate. The Board's review took into account the current system capacity of the pipelines reviewed; current spare capacity that could be dedicated to new exports; forecast growth in annual domestic requirements in the Canadian markets served by those pipelines; projected system facilities additions required to accommodate growth in domestic markets; and additional capacity required to carry the proposed new exports.

After having assessed the impact of the approval of new exports on Canadian pipeline systems, it is the Board's view that the new exports resulting from this decision will not create, in future, surplus capacity in existing pipeline systems of such magnitude as to suggest to the Board that some or all of the exports should not be approved. Indeed, there would appear to be considerable merit in prebuilding facilities on the TransCanada system both to accommodate new exports now and future growth in Eastern Canadian markets, while at the same time contributing to improved security of supply on the TCPL system.

The scope and findings of the Board's analysis of the current and future capacity requirements of the TransCanada and other Canadian pipeline systems are discussed in the sections following.

7.2.8.1 TransCanada

There was considerable debate during the hearing on the existence and availability of surplus capacity in the TransCanada system and, if there were surplus capacity, to whom that surplus should be allocated.

The TransCanada/Great Lakes System consists of three major sections: TCPL's Western Section, TCPL's Central Section, and the Great Lakes System. The throughput requirements of the TransCanada system are made up of three components: the Canadian requirements in existing market areas, projected Canadian requirements for the expansion markets east of the existing market areas, and export obligations. The total TransCanada throughput and current export obligations East of Alberta are shown in Table D-4 of Appendix D, in which the capability of the TransCanada System is analysed.

In order to determine the need for additional facilities on the TCPL system, the Board had to first establish TransCanada's current and forecast spare capacity in the Western and Central Sections.

As TransCanada's greatest requirements occur in the winter months, the surplus capability that exists in the winter is the limiting factor, at least in the Western Section. Based on data available to the Board from this and previous submissions made by TransCanada, it would appear that the Western Section will have spare capacity in the contract year 1980-81 of $10.52 \times 10^6 \text{ m}^3/\text{day}$ (371 MMcf/d) or $3.84 \times 10^9 \text{ m}^3/\text{year}$ (135 Bcf/year) on a firm basis. Although it would be possible to transport more gas, it is emphasized that this represents the limit of volumes that could be carried in the Western Section on a firm, year-round basis. In following years, the available surplus capacity would be diminished as the Canadian market grows.

In TCPL's Central Section, evidence indicated a surplus capability on a year-round firm basis of about $4.50 \times 10^6 \text{ m}^3/\text{day}$ (159 MMcf/d) for the gas year 1980-81. In the following year, there would be virtually no surplus capability on a firm basis. New facilities would be required by 1982-83, at the latest, to service the growth in demand in existing domestic markets. Because of the deliveries made under ACQ contracts, the surplus capacity of the Central Section during the summer would be slightly smaller than during the winter.

In assessing the demands on the Central Section of TransCanada, a review of the Great Lakes Gas Transmission system is required.

The Great Lakes system appears to the Board to have the capability of accepting up to $36.83 \times 10^6 \text{ m}^3/\text{day}$ of gas (1300 MMcf/d)

at Emerson, but is capable of delivering only $25.49 \times 10^6 \text{ m}^3/\text{day}$ (900 MMcf/d) back into Canada at the St. Clair River. Thus, if exports made via Great Lakes exceed $11.34 \times 10^6 \text{ m}^3/\text{day}$ (400 MMcf/d), Great Lakes's capability to redeliver gas to Canada at St. Clair would be diminished. Should this occur, and absent an expansion of the Great Lakes system, the only way continued assured deliveries of gas to Eastern Canada could be made would be by increasing throughput on the Central Section of TransCanada, entailing the addition of facilities on that Section.

TransCanada is currently authorized to export $9.53 \times 10^6 \text{ m}^3/\text{day}$ (336.4 MMcf/d) via the Great Lakes system. In addition, Great Lakes transports approximately $1.32 \times 10^6 \text{ m}^3/\text{day}$ (46.5 MMcf/d) for Consolidated. This total of $10.85 \times 10^6 \text{ m}^3/\text{day}$ (382.9 MMcf/d) of exports therefore leaves only a small surplus capacity of about $0.49 \times 10^6 \text{ m}^3/\text{day}$ (18 MMcf/d), and any increases in excess of that amount could not be based on firm deliveries. To the extent that existing export licences are not drawn upon at the maximum daily rate, this volume of $0.49 \times 10^6 \text{ m}^3/\text{day}$ could be increased.

TransCanada stated that if the application of Consolidated to export $5.66 \times 10^6 \text{ m}^3/\text{day}$ (200 MMcf/d) were approved, approximately $4.64 \times 10^6 \text{ m}^3/\text{day}$ (164 MMcf/d) of TransCanada's gas would have to be backed out of Great Lakes and be moved to Eastern Canadian markets via TCPL's Central Section.

While the Board found that a certain amount of spare capacity does exist in the TransCanada system, it is evident that exports arising from the Board's decision, as detailed in Chapter 9, would require the addition of new facilities in order that TransCanada could carry the newly-approved exports.

Utilizing the established current capacity and applying the annual growth increments determined by the Board in its forecast of natural gas demand in Canada, presented in Appendix G, the Board determined the nature and extent of capacity additions required by this export decision. The Board further estimated the degree to which these facility additions would be utilized to serve future Canadian needs as exports declined and terminated.

The Board based its analysis on the premise that future Canadian demand would be met by additional pipeline facilities constructed in Canada. The results of this analysis are presented in Tables 7.2.8.1 and 7.2.8.2 and in Figures 7.2.8.1 and 7.2.8.2.

The tables show the Board's estimate of the annual deliveries that will be made in each year from 1980 to 1994 through the Western and Central Sections of the TransCanada system, under two scenarios: a base case reflecting Canadian requirements and currently authorized exports, and an export case in which the new exports arising from the Board's decision have been added to the base case.⁽¹⁾

The Board's analysis of current and future requirements for capacity on the TransCanada system shows that with additional facilities constructed to carry the new export volumes in the early 1980's, there will be a slight surplus in pipeline capacity in the Western Section in the period 1986-93. It is the Board's view, however, that the size of this induced surplus will be very small in comparison with total transportation requirements on the system. For example, as shown in Table 7.2.8.1, the Board estimates that in 1987 the Western Section would have a maximum surplus capacity of only $1.63 \times 10^9 \text{ m}^3$ (59 Bcf), or 3.6 per-cent of the total capacity that would be in place at that time. The Board notes that this is smaller than the current surplus capacity in this section, both in terms of volume and as a percentage. The Board's study also shows that a second period of increased surplus capacity would occur on the Western Section in 1991. The Board notes that most of this surplus would have occurred in any event, resulting from the expiry of existing export licences.

With respect to the Central Section, the Board's analysis indicates that because of a decline in throughput requirements in 1986, spare capacity would occur in the period 1986-88, as shown in Table 7.2.8.2. As for the Western Section, this spare capacity would be, on a percentage basis, very small compared to total capacity. For example, as shown in Table 7.2.8.2, the Board estimates that in 1987 the Central Section would have a maximum spare capacity of $0.36 \times 10^9 \text{ m}^3$ (13 Bcf), or 1.4 percent of the total capacity that would exist at that time.

(1) Accordingly, exports to be made by Consolidated, Niagara, ProGas, Sulpetro and TransCanada (extension of Licence GL-1) are included.

Table 7.2.8.1

TRANSCANADA WESTERN SECTION

SUMMARY OF THROUGHPUT REQUIREMENTS AND REQUIRED CAPACITY ADDITIONS

NEB Estimates

10^9 m^3

YEAR	BASE CASE				EXPORT CASE				MARGINAL ADDITIONS DUE TO BOARD DECISION
	THROUGHPUT REQUIREMENT (1)	CAPACITY IN YEAR PREVIOUS	IDLE CAPACITY	REQUIRED ADDITIONAL CAPACITY	THROUGHPUT REQUIREMENT (2)	CAPACITY IN YEAR PREVIOUS	IDLE CAPACITY	REQUIRED ADDITIONAL CAPACITY	
1980	34.19	35.09	0.90	0.00	36.86	35.09	0.00	1.77	1.77
1981	34.40	35.09	0.69	0.00	41.97	36.86	0.00	5.11	5.11
1982	35.88	35.09	0.00	0.79	43.35	41.97	0.00	1.38	0.59
1983	37.28	35.88	0.00	1.40	44.27	43.35	0.00	0.92	-0.48
1984	39.08	37.28	0.00	1.80	45.86	44.27	0.00	1.59	-0.21
1985	41.02	39.08	0.00	1.93	45.87	45.86	0.00	0.01	-1.93
1986	41.94	41.02	0.00	0.93	44.31	45.87	1.56	0.00	-0.93
1987	43.16	41.94	0.00	1.22	44.24	45.87	1.63	0.00	-1.22
1988	44.53	43.16	0.00	1.38	44.53	45.87	1.34	0.00	-1.38
1989	45.65	44.53	0.00	1.11	45.65	45.87	0.22	0.00	-1.11
1990	45.43	45.65	0.21	0.00	45.43	45.87	0.44	0.00	0.00
1991	44.46	45.65	1.19	0.00	44.46	45.87	1.41	0.00	0.00
1992	44.72	45.65	0.93	0.00	44.72	45.87	1.15	0.00	0.00
1993	45.83	45.65	0.00	0.19	45.83	45.87	0.04	0.00	-0.19
1994	47.60	45.83	0.00	1.77	47.60	45.87	0.00	1.73	-0.04

NOTES:

EXISTING CAPACITY IS $35.09 \times 10^9 \text{ m}^3/\text{year}$

(1) From COLUMN 8 of TABLE D-5, Appendix D

(2) From COLUMN 8 of TABLE D-7, Appendix D

Table 7.2.8.2

TRANSCANADA CENTRAL SECTION
SUMMARY OF THROUGHPUT REQUIREMENTS AND REQUIRED
CAPACITY ADDITIONS
NEB Estimates
 10^3 m^3

YEAR	BASE CASE				EXPORT CASE				MARGINAL ADDITIONS DUE TO BOARD DECISION
	THROUGHPUT REQUIREMENT (1)	CAPACITY IN YEAR	IDLE CAPACITY	REQUIRED ADDITIONAL CAPACITY	THROUGHPUT REQUIREMENT (2)	CAPACITY IN YEAR	IDLE CAPACITY	REQUIRED ADDITIONAL CAPACITY	
1980	15.35	15.46	0.11	0.00	16.89	15.46	0.00	1.43	1.43
1981	16.60	15.46	0.00	1.14	22.07	16.89	0.00	5.18	4.04
1982	17.97	16.60	0.00	1.37	23.34	22.07	0.00	1.27	-0.10
1983	19.34	17.97	0.00	1.37	24.23	23.34	0.00	0.89	-0.48
1984	21.06	19.34	0.00	1.72	25.74	24.23	0.00	1.51	-0.21
1985	22.91	21.06	0.00	1.85	26.40	25.74	0.00	0.66	-1.19
1986	23.81	22.91	0.00	0.90	26.18	26.40	0.23	0.00	-0.90
1987	24.97	23.81	0.00	1.16	26.04	26.40	0.36	0.00	-1.16
1988	26.29	24.97	0.00	1.32	26.29	26.40	0.11	0.00	-1.32
1989	27.34	26.29	0.00	1.06	27.34	26.40	0.00	0.94	-0.11
1990	28.58	27.34	0.00	1.23	28.58	27.34	0.00	1.23	0.00
1991	30.04	28.58	0.00	1.46	30.04	28.58	0.00	1.46	0.00
1992	31.50	30.04	0.00	1.46	31.50	30.04	0.00	1.46	0.00
1993	33.00	31.50	0.00	1.50	33.00	31.50	0.00	1.50	0.00
1994	34.69	33.00	0.00	1.69	34.69	33.00	0.00	1.69	0.00

NOTES:

EXISTING CAPACITY IS $15.46 \times 10^3 \text{ m}^3/\text{year}$

(1) From COLUMN 12 of TABLE D-6, Appendix D

(2) From COLUMN 12 of TABLE D-8, Appendix D

TRANSCANADA PIPELINES

Summary of Throughput Requirements

NEB Estimates

FIGURE 7.2.8.1

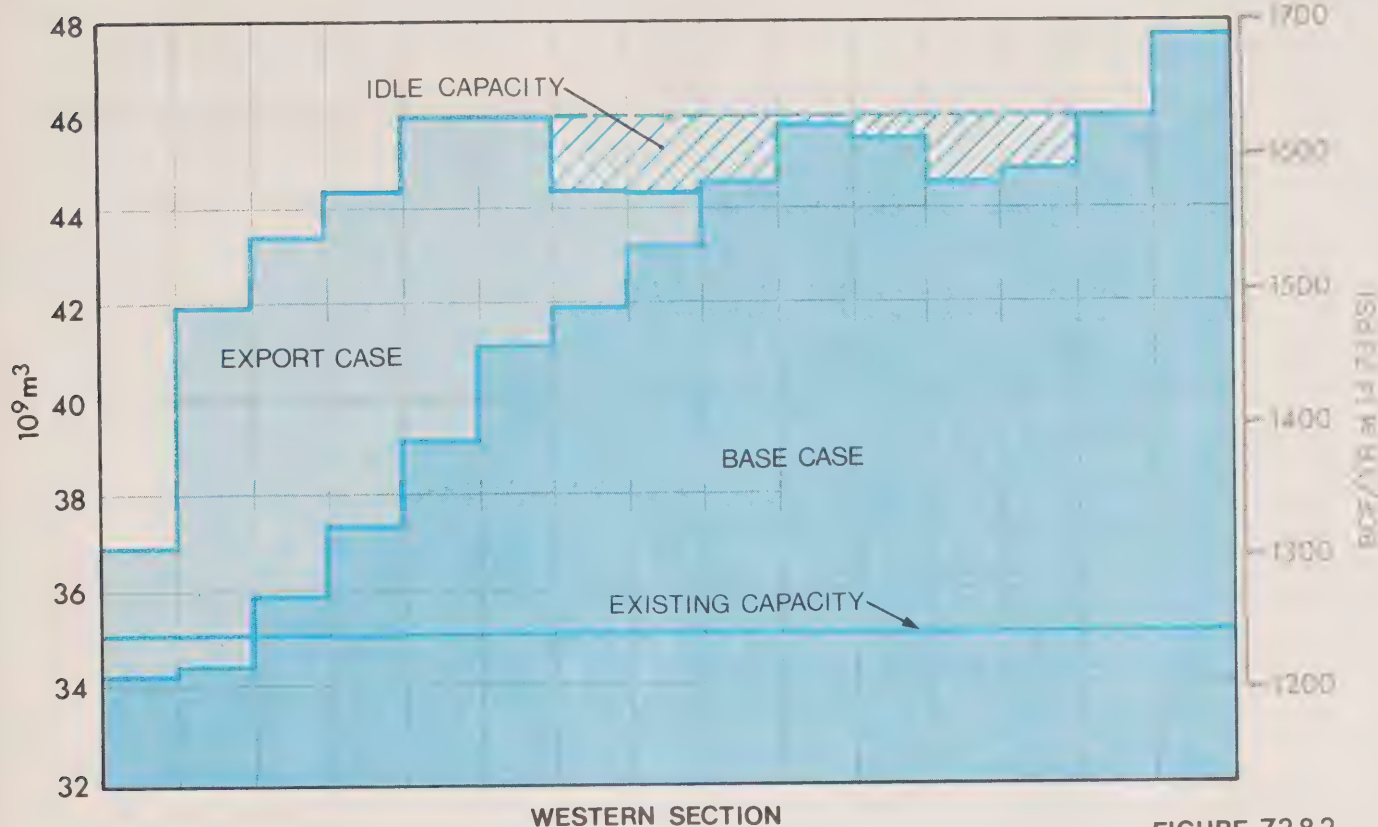
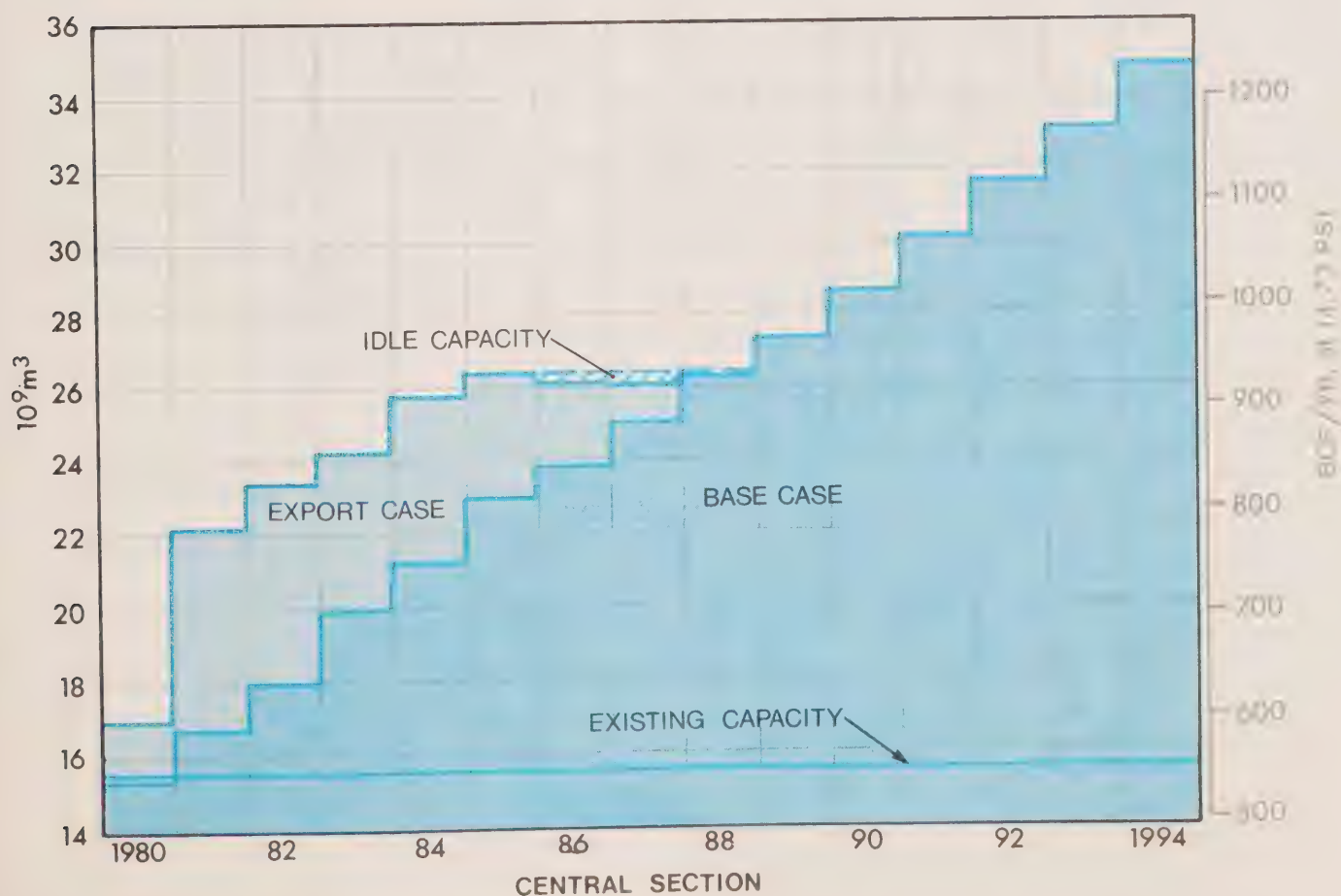


FIGURE 7.2.8.2.



In light of the foregoing, it is the Board's view that the new exports resulting from this decision will not create undue idle capacity in any portion of the TransCanada system of such a magnitude as to suggest that, as a result, some or all the exports should not be approved. As the Board has found in other proceedings, it believes that there should be a certain minimal percentage of spare capacity on main transmission systems in the interests of security of supply. The Board notes that the surplus capacity on the TransCanada system, which it has estimated will result from its decision, is of a magnitude in keeping with prudent pipeline design practices.

7.2.8.2 Other Pipeline Systems

As it had done in its analysis of the TransCanada system, the Board has assessed the impact of the approval of the applied-for exports on other transmission systems that will carry gas to be exported following the Board's decision. However, the question of the capability of the other pipeline systems involved, i.e., Westcoast, Alberta Natural, Foothills, Canadian-Montana, and Niagara, to move the proposed new exports was not at issue at the Hearing. With the exception of Westcoast, the Board has satisfied itself that the capacity is adequate. Westcoast indicated that it would require some additional facilities not only to deliver to Huntingdon the proposed additional daily volumes of gas to be exported under Licence GL-41, but also to carry the proposed Columbia exports. Westcoast stated that it would seek to obtain Board approval for the looping program it had sought earlier in its application which had been adjourned sine die by the Board on 29 May 1979.

CHAPTER 8SURPLUS8.1 Introduction

In its disposition of applications to export natural gas, the Board can issue licences, subject to the approval of the Governor in Council, only if it has first satisfied itself that the quantity of gas to be exported is surplus to the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of gas in Canada.

8.2 Surplus Determination Tests

In the 1979 Gas Report, the Board described the new procedures it had adopted to determine whether a surplus of natural gas existed. Surplus is now determined by using the following three tests, all of which have to be met before the Board deems a surplus to exist:

The Current Deliverability Test

This test is based on the level of deliveries possible each year from established reserves. For there to be a surplus, deliverability from these reserves has to be able to meet annual Canadian requirements plus currently-authorized exports for a minimum period. At the present time, the Board believes this period should be five years. If this minimum period of highly assured protection for existing requirements cannot be satisfied, there is no surplus. If existing requirements can be satisfied, gas can be declared surplus to the extent there is estimated spare deliverability over and above Canadian requirements plus authorized exports.

The Current Reserves Test

This test compares the inventory of established reserves with 25 times the first year's Canadian demand, plus currently-authorized exports. If the available established reserves are less than these requirements, there is no surplus. If reserves exceed these requirements, the amount of the excess can be declared surplus.

The Future Deliverability Test

This test is based on the level of deliveries possible each year from established reserves and from estimated future additions to these reserves. Deliverability from these reserves has to be able to meet forecast annual Canadian requirements plus currently-authorized exports for

some ten years into the future; otherwise, no surplus is deemed to exist. If forecast deliverability exceeds these requirements, the amount of the excess can be declared surplus.

8.3 Surplus Calculation Procedures

As previously mentioned, the Board's new procedures require all three surplus tests to be met before the Board deems a surplus to exist.

Of the three tests, only the second, the Current Reserves Test, establishes in one step the precise size of a surplus at a specific point in time. This is because this test involves the comparison of a known inventory of established reserves with a readily-calculable requirement for Canadian markets and existing export licences.

The two Deliverability Tests, on the other hand, involve the comparison of estimated annual production profiles with forecasts of annual requirements. The Board has developed a computer model to make these comparisons, and only when the calculations have been completed can the Board determine whether the Deliverability Tests are satisfied and, if so, what the dimensions of the surplus are.

Within the Deliverability Tests there are various steps which must be carried out. These steps are:

Tracking Existing Demand

First, the Board must estimate how far into the future deliverability can track (i.e. meet) Canadian requirements plus authorized exports. In the Current Deliverability Test, deliverability must be able to track demand for a minimum period of five years. In the Future Deliverability Test, it must be able to track demand for some ten years. Obviously, if this first step indicates that either of the Deliverability Tests is not satisfied, there is no surplus, and it is, therefore, not necessary to go beyond this step.

Capability

Second, the Board estimates the maximum level of deliverability (i.e. capability), unrestricted by demand. A comparison between the projections of capability and Canadian requirements plus authorized exports indicates the theoretical maximum quantity of gas available for new exports. In practice, licences for new exports generally would provide for uniform annual amounts for a fixed number of years and, therefore, the total amount of exports authorized would be less than the theoretical maximum.

Tracking the Applied-for Exports

The Board then estimates whether deliverability can track (i.e., meet) Canadian requirements and currently-authorized exports plus the applied-for exports. This step may indicate that there is insufficient deliverability to meet the requirements of all the applied-for exports, while, at the same time, satisfying the requirements of the two Deliverability Tests. In this case, the Board must determine the amount of exports it can authorize in a manner that would satisfy the two Deliverability Tests.

Verifying the Decision

As a final step, the Board ensures that the decision satisfies all three tests.

8.4 Input into Surplus Determination

In reaching its conclusions with respect to the determination of surplus, the Board has made the following assumptions:

Supply

The Board has used its estimates of supply discussed in Chapter 3 of this Report.

Canadian Requirements

As discussed in Chapter 4 of this Report, the Board has relied on its estimate of Canadian requirements contained in its February 1979 Gas Report. That estimate included an allowance for potential sales of natural gas in expansion markets in Quebec and the Atlantic Provinces.¹

Currently-Authorized Exports

In order to determine the surplus, the Board had to establish the annual quantities which might be exported under existing licences and the length of time over which these exports might take place. The allowance made for annual exports under existing licences is tabulated in Appendix E. The Board made the following assumptions in making allowance for the amounts and the duration of possible annual exports under existing licences:

- (1) For licences containing conditions permitting annual averaging, the maximum daily licensed quantity (adjusted for heat content) times the number of days in the year was used;
- (2) For licences not containing conditions permitting annual averaging, the maximum annual licensed quantity (adjusted for heat content) was used; and
- (3) With respect to the duration of the allowance specified in (1) and (2) above, the lesser of the following periods was used:
 - (a) until the expiry of the term of the licence; or
 - (b) until that time at which the remaining term volumes would have been exhausted if the licensee were to export at the level of the annual licensed quantity (without recourse to any annual averaging permitted under the licence).

In some cases, the use of the lesser of (a) or (b) above results in the total quantities for which allowance is being made being higher or lower than the term volumes specified in the licences. In aggregate the difference is insignificant. In the early years of the forecast period, the allowance made for exports exceeds the level of exports the Board expects will prevail. The Board believes this is a conservative approach, providing an additional margin of protection in the application of the Deliverability Tests. In any event, the allowances made by the Board in no way impinge on the rights of existing licensees to operate within the existing conditions of their licences.

8.5 The Board's Findings on Surplus

Having regard to the foregoing, the Board has made its findings with respect to its three surplus tests, discussed in the sections that follow:

8.5.1 Current Deliverability Test

Tracking Existing Demand

The Board finds that estimated annual deliverability from established reserves can track (i.e. meet) estimated annual Canadian requirements plus authorized exports up to and including 1990, as shown in Column 4 of Table 8.2.2 and on Figure 8.2.2. This period of eleven years exceeds the minimum period of five years that the Board established under the Current Deliverability Test to provide for the highly assured protection of existing requirements.

Capability

The Board finds that the theoretical maximum level of deliverability from established reserves (i.e. capability), unrestricted by demand, exceeds Canadian requirements plus authorized exports until after 1987. Current capability is shown in Column 5 of Table 8.2.2 and on Figure 8.2.2. The theoretical maximum surplus under the supply curve totals some 6.4 EJ.

Tracking the Applied-for Exports

The Board finds that the estimated deliverability from established reserves tracks (i.e. meets) Canadian requirements and authorized exports plus applied-for exports up to and including 1984, as shown in Column 8 of Table 8.2.2 and on Figure 8.2.2. From 1985 to 1987 inclusive, some surplus would be available for export at levels below those requested. In any event, no surplus would exist under the Current Deliverability Test after 1987. Under this step of the Current Deliverability Test, the maximum quantity that would be available for export in the pattern applied for, plus associated fuel for transportation in Canada, is approximately 4.8 EJ.

8.5.2 Current Reserves Test

The Current Reserves Test has been calculated as of 31 December 1979 using the Board's projected estimate of established reserves. It results in a current reserves surplus of 10.6 EJ, as shown in Table 8.2.3. This is the maximum quantity that could be declared surplus, in the absence of restrictions imposed by application of the two Deliverability Tests. It may be compared with the current reserves surplus of 4.0 EJ (3.8 Tcf) as of 31 December 1978 shown in the Board's 1979 Gas Report. The current reserves surplus of 10.6 EJ exceeds that determined under the Current Deliverability Test.

8.5.3 Future Deliverability Test

Tracking Existing Demand

The Board finds that estimated annual deliverability from established reserves and from additions to reserves can track forecast annual Canadian requirements plus authorized exports up to and including 1997, as shown in Column 4 of Table 8.2.4 and on Figure 8.2.4. This period of eighteen years exceeds the protection of some ten years judged by the Board to be the minimum acceptable.

TABLE 8.2.2

CURRENT DELIVERABILITY TEST

Year	(Petajoules/Year)									
	(1) Domestic Demand	(2) Existing Licences	(3) Total (1 + 2)	(4) Tracking Col. (3)	(5) Supply Capability	(6) Applied-for Exports	(7) Allowance For Fuel	(8) Total (3+5+7)	(9) Tracking Col. (8)	(10) Deficiency (8 - 9)
1980	2067	1168	3235	3235	4328	132	10	3377	3377	0
81	2143	1125	3268	3268	4429	471	29	3768	3768	0
82	2229	1062	3291	3291	4463	798	35	4124	4124	0
83	2323	1056	3379	3379	4480	780	33	4192	4192	0
84	2424	1059	3483	3483	4304	780	33	4296	4296	0
1985	2534	1042	3576	3576	4202	784	33	4393	4332	61
86	2603	925	3528	3528	3878	773	26	4327	4134	193
87	2661	755	3416	3416	3545	889	26	4331	3795	536
88	2731	757	3488	3488	3219	840	22	4350	3446	904
89	2784	613	3397	3397	2940	776	19	4192	3103	1089
1990	2841	246	3087	3087	2690	720	21	3828	2834	994
91	2900	147	3047	3001	2424	698	20	3765	2568	1197
92	2987	63	3050	2746	2215	673	19	3742	2316	1426
93	3087	54	3141	2486	2024	650	18	3809	2110	1699
94	3176	14	3190	2259	1823	608	17	3815	1908	1907
1995	3275	12	3287	2067	1650	412	12	3711	1693	2018
96	3367		3367	1870	1465			3367	1532	1835
97	3464		3464	1688	1379			3464	1442	2022
98	3568		3568	1509	1255			3568	1306	2262
99	3675		3675	1391	1136			3675	1173	2502
2000	3789		3789	1286	1042			3789	1064	2725

- Column (1) is the total domestic demand which includes provision for expansion markets and fuel for existing export licences as tabulated on page 5 of Appendix G.

- Column (2) is the allowance made for existing licences as explained in Chapter 8 and as tabulated on page 2 of Appendix E.

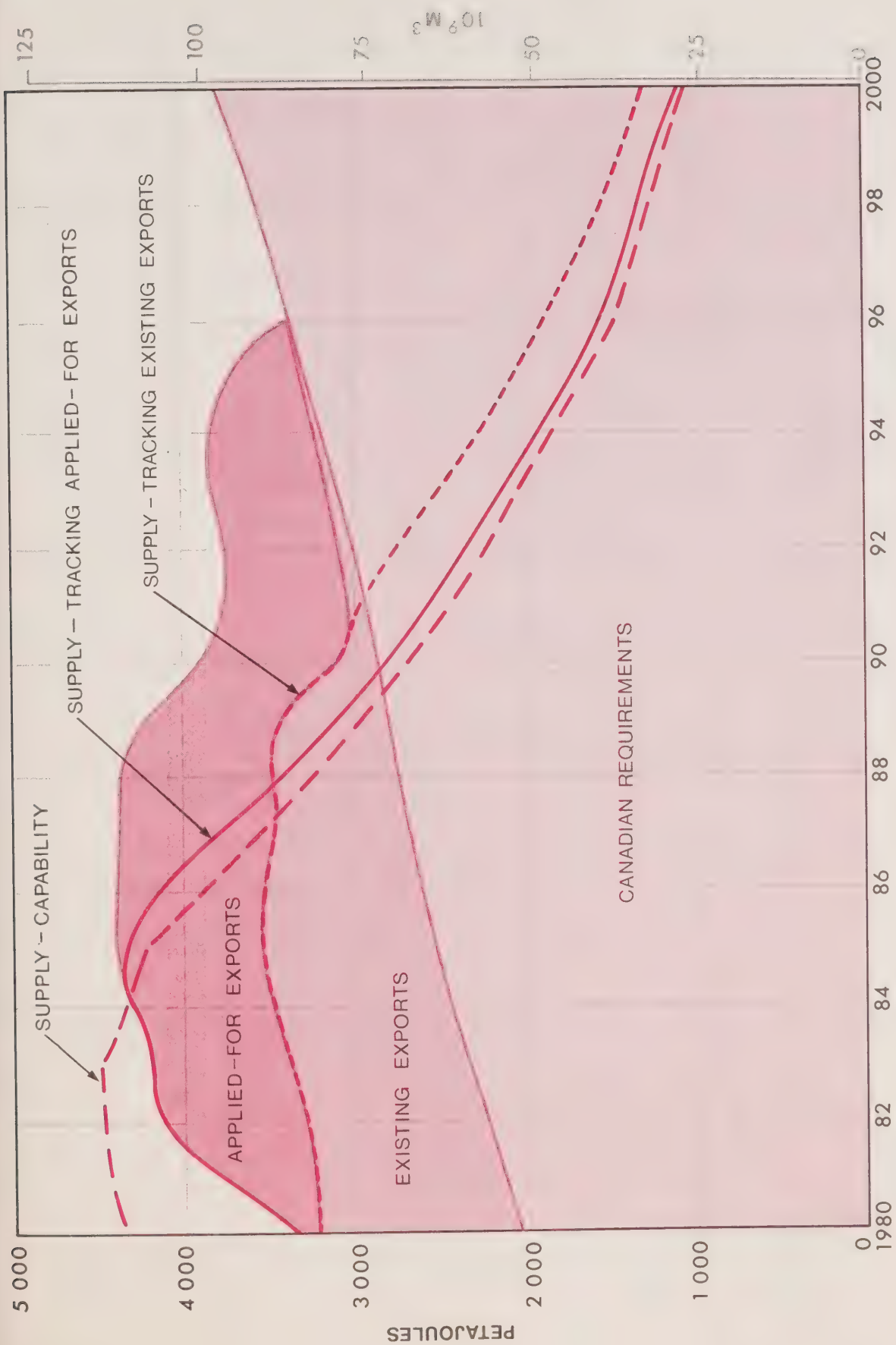
- Column (4) is the current supply tracking total requirements shown in column (3).

- Column (5) is the current supply capability from established reserves unrestricted by demand.

- Column (6) is the allowance made for the total applied-for export quantities as tabulated on page 3 of Appendix E.

- Column (7) is the incremental fuel for the applied for exports.

- Column (9) is the current supply tracking total requirements shown in column (8).



CURRENT DELIVERABILITY TEST
Canadian Requirements Plus Existing and Applied - for Exports

CURRENT RESERVES TEST

(Exajoules)

	As of 31 Dec. 1979
Remaining Established Reserves ⁽¹⁾	75.7
Less Deferred Reserves ⁽²⁾	1.2
Less One-half of Reserves Beyond Economic Reach ⁽³⁾	1.3
Less Processing Shrinkage ⁽⁴⁾	<u>4.8</u>
Total Supply	<u>68.4</u>
Canadian Sales except Alberta ⁽⁵⁾	32.6
Alberta Sales ⁽⁶⁾	14.5
Authorized Export Sales ⁽⁷⁾	<u>10.7</u>
Total Requirements (including pipeline fuel)	<u>57.8</u>
Current Reserves Surplus (Total supply less total requirements)	<u>10.6 EJ</u>

Notes

- (1) No allowance has been made for frontier reserves.
- (2) The total deferred reserves in Alberta are estimated to be 4.4 EJ, with 3.2 EJ expected to be connected within 25 years.
- (3) Beyond Economic Reach reserves are estimated as 2.3 EJ for Alberta and 0.3 EJ for British Columbia.
- (4) Processing shrinkage is based on expected hydrocarbon removal at straddle plants (calculated in the same manner as tabulated in Table 5-2 of the 1979 Gas Report).
- (5) Canadian Sales except Alberta include pipeline fuel and losses in Canada, except for Alberta, but do not include fuel used in Canada for exports. They are 25 times the annual demand (less Alberta) of 1.305 EJ for 1980.
- (6) Alberta Sales include pipeline fuel and losses in Alberta. They are 25 times the projected demand for Alberta of 0.58 EJ for 1980, but do not include fuel used in Alberta for exports.
- (7) Authorized Export Sales includes all currently authorized licenced exports estimated to be remaining on 31 December 1979 plus an allowance of 0.4 EJ for fuel used in Canada to transport these quantities.

Capability

Production at the absolute maximum level of deliverability from established reserves and from additions to these reserves allows Canadian requirements, authorized exports, and applied-for exports to be met up to and including 1991, as shown in Column 5 of Table 8.2.4 and on Figure 8.2.4. The theoretical maximum surplus under the capability curve is some 14.5 EJ.

Tracking the Applied-for Exports

The Board finds that deliverability from established reserves and from additions to reserves tracks Canadian requirements and authorized exports as well as applied-for exports up to and including 1992, as shown in Column 8 of Table 8.2.4 and on Figure 8.2.4. Under this step of the Future Deliverability Test, the maximum quantity that would be available for export in the pattern applied for, plus associated fuel for transportation in Canada, is approximately 10.0 EJ.

TABLE 8.2.4

FUTURE DELIVERABILITY TEST

(Petajoules/Year)

Year	(1) Domestic Demand	(2) Existing Licences	(3) Total (1 + 2)	(4) Tracking Col. (3)	(5) Supply Capability	(6) Applied-for Exports	(7) Allowance For Fuel	(8) Total (3+6+7)	(9) Tracking Col. (8)	(10) Deficiency (8 - 9)
1980	2067	1168	3235	3235	4353	132	10	3377	3377	0
81	2143	1125	3268	3268	4513	471	29	3768	3768	0
82	2229	1062	3291	3291	4649	798	35	4124	4124	0
83	2323	1056	3379	3379	4818	780	33	4192	4192	0
84	2424	1059	3483	3483	4813	780	33	4296	4296	0
1985	2534	1042	3576	3576	4875	784	33	4393	4393	0
86	2603	925	3528	3528	4702	773	26	4327	4327	0
87	2661	755	3416	3416	4508	889	26	4331	4331	0
88	2731	757	3488	3488	4307	840	22	4350	4350	0
89	2784	613	3397	3397	4139	776	19	4192	4192	0
1990	2841	246	3087	3087	3983	720	21	3828	3828	0
91	2900	147	3047	3047	3793	698	20	3765	3765	0
92	2987	63	3050	3050	3642	673	19	3742	3742	0
93	3087	54	3141	3141	3492	650	18	3809	3761	48
94	3176	14	3190	3190	3316	608	17	3815	3585	230
1995	3275	12	3287	3287	3154	412	12	3711	3382	329
96	3367		3367	3367	2968			3367	3220	147
97	3464		3464	3464	2868			3464	3119	345
98	3568		3568	3415	2721			3568	2960	608
99	3675		3675	3241	2571			3575	2790	885
2000	3789		3789	3072	2456			3789	2647	1142

- Column (1) is the total domestic demand which includes provision for expansion markets and fuel for existing export licences as tabulated on page 5 of Appendix G.

- Column (2) is the allowance made for existing licences as explained in Chapter 8 and as tabulated on page 2 of Appendix E.

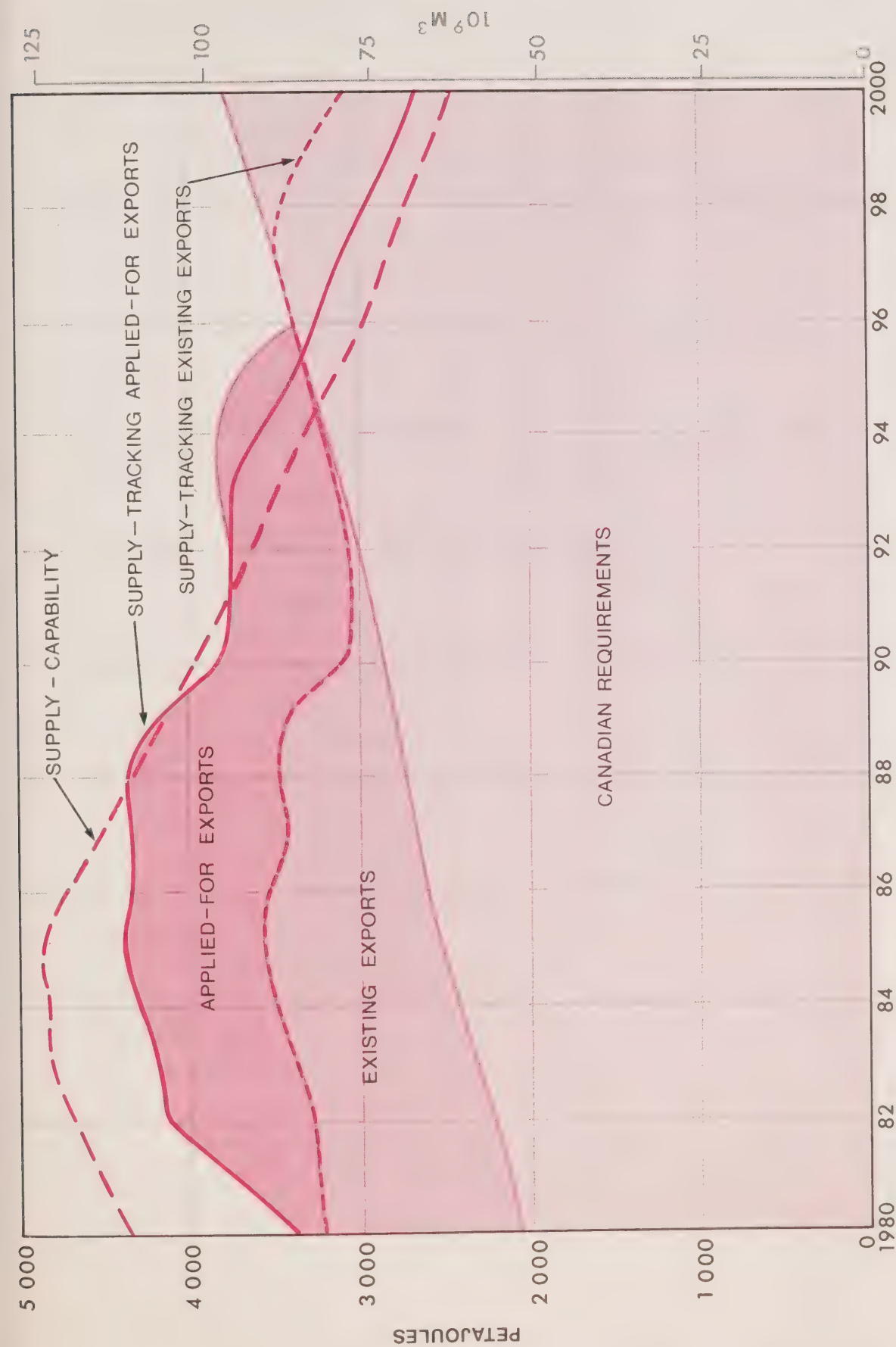
- Column (4) is the future supply tracking total requirements shown in column (3).

- Column (5) is the future supply capability from established reserves plus reserves additions unrestricted by demand.

- Column (6) is the allowance made for the total applied-for export quantities as tabulated on page 3 of Appendix E.

- Column (7) is the incremental fuel for the applied for exports.

- Column (9) is the future supply tracking total requirements shown in column (8).



FUTURE DELIVERABILITY TEST
Canadian Requirements Plus Existing and Applied-for Exports

CHAPTER 9DECISION9.1 General Comments

After considering the evidence adduced at the hearing, and after taking into account all matters that appear to it to be relevant, the Board is satisfied that it would be in the public interest to authorize new exports of natural gas. It has determined that net economic benefits of \$6.5 billion would flow to Canada as a result of the exports arising from the following decision. The details of the Board's cost/benefit analysis are contained in Appendix F.

The Board has considered the impact of the approval of the applications on the requirement for facilities additions in Canada, and, among other things, other general issues discussed in Chapter 7. The Board is satisfied that the price to be received for the gas is just and reasonable in relation to the public interest.

With respect to the term of licences which the Board is prepared to issue, the Board has explained in section 7.2.7 the factors it has taken into account in considering the length of such licences. In light of the Board's findings in section 8.5.1 under the Current Deliverability Test, the Board concludes that it can issue licences for the full amount of the applied-for exports through 1984, and at reduced levels through 1987. Accordingly, the Board will issue licences which incorporate, in general, a phasing down of new exports by 25 percent per year of the quantities sought, to provide for exports in 1985 at 75 percent, 50 percent in 1986, and 25 percent in 1987. The daily maximum quantities during the phase-down period (1985-87) were calculated based on the load factor applied for in each of the applications. The periods of the proposed licences will be on a contract year or calendar year basis, in accordance with the applications, adjusted where necessary to phase in with existing licence authorizations.

The Board believes it would be appropriate to repeat its views with respect to the Future Deliverability Test. Although many of the Applicants applied for authorization of "conditional" exports under the

Future Deliverability Test, the Board wishes to reemphasize that this test was included in the new surplus determination procedures to ensure that potential new exports would not cause a future deliverability shortfall to occur within ten years. Additionally, the Board could use this test to grant extended licences on a conditional basis if the Board felt it would be in the public interest to do so. The Board has considered the various applications for extended or conditional exports and has decided that none are merited at this time.

The Board has examined the individual supply positions of each of the Applicants vis-a-vis the applied-for quantities. Given the current level of uncommitted reserves and the fact that the Board expects a major portion of the reserves it has categorized as "uncommitted" to be in fields and pools already controlled by the Applicants, the Board has found that each Applicant has an adequate supply available to allow it to meet its various current obligations (where such exist) and to meet the level of exports the Board is prepared to approve. The Board recognizes that some Applicants may encounter minor deficiencies in deliverability due to field start-up problems, but judges that these are not significant.

The Board notes that a number of the Applicants have requested various forms of "make-up" clauses, or averaging conditions, in the exports to be authorized. With the introduction of deliverability tests, it is no longer practical for the Board to allow annual averaging conditions in new licences. Annual averaging conditions require the Board to set aside supply in each year to allow for the delivery of the maximum quantity allowed by such licences. If, in practice, the exports are taken at a low load factor, the quantities of gas which comprise the difference between the maximum allowable and actual deliveries become cumulatively "locked-in". If the licences do not contain "make-up", clauses, the gas that would otherwise be "locked-in" would be available for dedication to other markets, including other export markets. The term quantity of all new licences will be the sum of the annual authorized quantities.

As indicated on page 8-3, as a final step in the surplus determination procedure, the Board verifies that its decision is consistent with the provisions of the three surplus tests. Having completed the verification procedure, the Board finds:

- a. the total quantity of new exports to be authorized is 4.1 EJ ($106.2 \times 10^9 \text{ m}^3$), and the additional pipeline fuel required in Canada to transport those quantities is 0.2 EJ (per Table G-12 of Appendix G). The combined quantity of 4.3 EJ is less than the 10.6 EJ potentially exportable under the Current Reserves Test; thus that test is satisfied.
- b. the supply-demand balance shown in Appendix G reflects that available gas supplies exceed requirements to meet total demand in Canada. Table G-12 in Appendix G shows that Current Deliverability from established reserves tracks the decision for a period of eight years. Accordingly, as the minimum period of highly assured protection of five years is exceeded, the Current Deliverability Test is satisfied.
- c. the Board finds that future deliverability can track Canadian requirements, authorized exports, as well as total applied-for exports up to and including 1992. Therefore, as no exports have been granted under the Future Deliverability Test and as the exports to be approved are considerably less than applied for quantities, the Future Deliverability Test is satisfied.

The Board has set out in the following sections its decision on each application, including, in summary form, the conditions of orders and licences to be issued arising from the decision. The detailed conditions to be contained in each licences and order to be issued are given in Appendix H. At Table 9.1, the Board has shown the quantities of gas which could be exported annually as a result of its decision.

9.2 Alberta and Southern

This Company sought the extension of Licences GL-35 and GL-3 for the period commencing 1 November 1985 for GL-35 and 1 November 1986 for GL-3, and terminating on 31 October 1989 for both licences. It sought approval to export 20 673 940 800 cubic metres during the extension period.

Table 9.1

ANNUAL NATURAL GAS EXPORTS
ARISING FROM DECISIONCalendar Year Quantities
(Petajoules)

	Licence	GHV ⁽¹⁾ (MJ/m ³)	Term	Calendar Year Quantities (Petajoules)								
				1980	1981	1982	1983	1984	1985	1986	1987	
SOUTH FROM ALBERTA	A&S	38.76	42.0*									
		38.76	55.6*							7.0	35.0	
	OMPL	38.30	3.0*						6.2	34.0	15.4	
	CARDSTON	38.30	3.3							0.5	2.5	
	GL-36	38.30	3.0*							1.7	1.6	
WTCL PANALB	ADEN	36.78	67.7	10.4	10.4	10.4	10.4		0.3	1.8	0.8	
	GL-4	38.76	246.2*		3.4	56.0	56.0	10.4	7.8	5.2	2.6	
	KINGSGATE	39.05	534.4	16.2	97.2	97.2	97.2	53.7	39.7	25.7	11.7	
	MONCHY	39.05	1457.5		54.1	323.9	323.9	93.1	68.8	44.5	20.2	
								310.4	229.4	148.4	67.4	
TOTAL	SOUTH		2412.7	26.6	165.1	487.5	487.5	467.6	352.2	268.8	157.2	
BRITISH COLUMBIA	COLUMBIA	38.94	93.1	14.3	14.3	14.3	14.3	14.3	10.8	7.2	3.6	
EAST FROM ALBERTA	SULPETRO	37.86	69.6	27.1	23.2	19.3						
	CNG	37.86	430.7	13.1	78.3	78.3	78.3	75.0	55.5	35.9	16.3	
	TCPL	37.86	411.7	42.6	79.4	79.4	79.4	79.4	51.5			
	NGT	37.86	27.2	3.9	3.4	3.4	3.2	3.2	3.0	4.7	2.2	
	PROGAS	37.86	645.6	19.6	117.4	117.4	117.4	112.5	83.1	53.8	24.4	
TOTAL	EAST		1584.8	106.3	301.7	297.8	278.5	270.1	193.1	94.4	42.9	
CANADA	TOTAL		4090.6	147.2	481.1	799.6	780.3	752.0	556.1	370.4	203.7	

* Quantity added to existing licence.

(1) Gross Heating Value: The heat liberated in megajoules by burning one cubic metre of moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Both proposed licence extensions would go beyond the period of surplus deliverability determined under the Current Deliverability Test. While Alberta and Southern stated it was applying for such extensions now in order to allow its customers the opportunity to plan their future supply, even if additional exports could only be granted on a conditional or interruptible basis, the Board concludes that such an argument is not a compelling reason to grant a conditional licence.

The evidence showed that while Alberta and Southern has sufficient total reserves to meet its total potential requirements, Alberta and Southern would be faced with deficiencies in deliverability during the 1982 to 1989 period, unless it was able to contract for additional gas supplies. However, the Board notes that Alberta and Southern's contract with Pan-Alberta terminates on 31 October 1986, and that the quantity of new exports will be reduced from the requested levels⁽¹⁾ by the phase-down procedure commencing in 1985. As the level of new exports would be reduced to 50 percent of applied-for levels in 1986, the Board concludes that Alberta and Southern will not encounter deliverability difficulties in 1986 or 1987 to the extent that it would be unable to meet its various sales commitments.

Alberta and Southern also applied for a condition, to be included in the licences that may be issued to it, to provide that, notwithstanding the quantity of gas that may be designated by the Board as exportable in any one day, Alberta and Southern be permitted to export 110 percent of that quantity for the purposes only of alleviating temporary operating problems caused by pipeline or equipment failure. Such a condition is consistent with existing conditions in Licences GL-3 and GL-35, and the Board concludes that it would be in the public interest to approve this request.

(1) In addition to Alberta and Southern's application, both Canadian-Montana and Pan-Alberta would draw upon Alberta and Southern supplies to make new exports.

The Company also proposed that the Board include the following condition in its licence renewals:

"that the quantity of gas that may be exported from Canada under the authority of and in accordance with such extension is to be subject to such limitations as the Board may impose in the event that during the term of such extension any portion of such gas may be required to meet the Canadian requirements and authorized firm exports."

The Board has considered this proposal in light of Alberta and Southern's total application. In the Board's view, the proposed licence condition would be appropriate if the Board were to approve the conditional export of gas under the Future Deliverability Test. As the only exports the Board is prepared to approve are firm exports under the Current Deliverability Test, the Board concludes that it is not necessary to include the proposed condition in the authorizations to be granted to Alberta and Southern.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board is not prepared to approve the extension of the term of the licences requested by Alberta and Southern. However, the Board is prepared to issue orders amending Licences GL-3 and GL-35 as set out in Appendix H, and as summarized as follows:

- a. to extend Licence GL-3 for one year commencing 31 October 1986, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	31 Oct 86 - 31 Oct 87	3 248 900	1 085 500 000

- (ii) a total quantity that may be exported during the period of the extension of 1 085 500 000 cubic metres.
- (iii) the export on any one day of 110 percent of the daily quantities authorized for the purposes of alleviating temporary operating problems caused by pipeline or equipment failure.

- b. to extend Licence GL-35 for two years commencing 1 November 1985, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	1 Nov 85 - 31 Oct 86	2 903 600	956 100 000
	1 Nov 86 - 31 Oct 87	1 451 800	478 100 000
(ii)	a total quantity that can be exported during the period of the extension of 1 434 200 000 cubic metres.		
(iii)	the export on any one day of 110 percent of the daily quantities authorized for the purposes of alleviating temporary operating problems caused by pipeline or equipment failure.		

9.3 Canadian-Montana

Canadian-Montana made two separate applications for the export of gas. In the first application, the Company sought:

- to obtain a new eight-year licence commencing 1 January 1980 authorizing annual exports of 283 million cubic metres of gas to be produced from the Aden area;
- the addition of some 2 276 million cubic metres to Licences GL-5, GL-17, GL-25, and GL-36 to replace gas already exported under accelerated export authorizations; and,
- the reinstatement of certain licence conditions which had been changed since Licence GL-8 expired in June 1973.

In its second application, Canadian-Montana sought to extend the term of Licences GL-5 and GL-36 for periods of three and four years, respectively, both to end 31 October 1989. The proposed extension would have added 1 344 155 800 cubic metres to the total term quantities under the two licences.

With respect to Canadian-Montana's application for a new licence to export gas at Aden, the Board notes that gas from this region has been exported by Canadian-Montana for over 20 years and no new facilities would be required. The Board is satisfied that the remaining established reserves of $8.3 \times 10^9 \text{ m}^3$ exceed the volume of gas for which a new

licence has been requested. As the term of the licence requested, i.e., eight years, conforms with the period of surplus determined by the Current Deliverability Test, the Board is prepared to recommend the issuance of an eight-year licence. However, the final three years would be subject to reduced export levels in common with the treatment accorded other Applicants.

With respect to the application to amend Licences GL-5, GL-17, GL-25, and GL-36, Canadian-Montana argued that the addition of the "replacement volumes" in the licences would prevent their "premature" expiry, which would otherwise occur because of the accelerated rates of take allowed by the Board subsequent to the expiry of Licence GL-8. The Board cannot view Canadian-Montana's request to restore volumes to Licences GL-5, GL-17, GL-25, and GL-36 as other than a straightforward application to increase the allowable volumes under these licences. As the Board has provided for the extension of Licences GL-5 and GL-6 separately, and as the Board finds that Licence GL-17 will have gas remaining under it beyond 1988, the only licence to which the Board could provide additional gas under the phase-down procedure of the Current Deliverability Test is Licence GL-25 because, theoretically, Canadian-Montana would exhaust the remaining term volumes under Licence GL-25 by mid-1986 if it continues exporting at maximum authorized levels. Accordingly, the Board concludes that although it could provide for the addition of gas to Licence GL-25, to do so under the phase-down procedure, which applies to authorizations in 1986-87, could require taking away certain rights in that period now existing under the licence. Instead, it would be preferable to issue a new licence for the equivalent amount.

With respect to Canadian-Montana's requests for the reinstatement of earlier licence conditions in its four licences, the Board recognizes that with the approval of a new licence authorizing exports at Aden, the conditions added to the licences since 1 June 1973 providing for the adjustment for the loss of Licence GL-8 are no longer necessary. Accordingly, the Board is prepared to issue orders to amend the conditions contained in Licences GL-5, GL-17, GL-25, and GL-36 as requested by Canadian-Montana.

Canadian-Montana's second application followed Alberta and Southern's application to extend Licences GL-3 and GL-35. Canadian-Montana stated that, as its Licences GL-5 and GL-36 "were similar in all

respects to the export licences held by Alberta and Southern except as to authorized volumes and export points", and that, as A & S had filed to extend its licences, Canadian-Montana therefore was filing a similar application for its licences. The Board agrees that, historically, there has been a parallel in the issuance and continuation of the two sets of licences, and concludes that it would be in the public interest to extend Canadian-Montana's Licences GL-5 and GL-36 in a manner similar to the extension of Alberta and Southern's licences.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board is not prepared to approve Canadian-Montana's application for an increase in the total volumes of gas authorized for export under the Company's four existing Cardston Licences. Accordingly, Canadian-Montana's application to add $466 \times 10^6 \text{ m}^3$ to Licence GL-5, $264 \times 10^6 \text{ m}^3$ to Licence GL-17, $1\,522 \times 10^6 \text{ m}^3$ to Licence GL-25, and $23 \times 10^6 \text{ m}^3$ to Licence GL-36 is denied. However, the Board is prepared to issue a new licence for exports at Cardston, as set out in Appendix H, and as summarized below.

Furthermore, while the Board is not prepared to approve the term of the new licence and licence extensions requested by Canadian-Montana, the Board is prepared to issue a new licence for exports at Aden, to issue orders amending Licences GL-5 and GL-36, and to vary Licences GL-5, GL-17, GL-25, and GL-36 in the manner requested by Canadian-Montana, all as set out in Appendix H, and as summarized as follows:

- a. to authorize new exports of gas at Cardston, Alberta, for a two-year period commencing 1 July 1986,⁽¹⁾ providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m^3)	<u>Annual</u> (m^3)
	1 Jul 86 - 31 Oct 86	339 950	34 500 000
	1 Nov 86 - 31 Oct 87	169 975	51 700 000

(1) Estimated date on which full term volumes will have been exported under Licence GL-25.

(ii) notwithstanding the annual maximum shown, the Licensee may not export under this licence during either annual period a quantity of gas which in sum with exports made during the same annual period under Licence GL-25 would exceed 206 800 000 cubic metres.

(iii) a total quantity that may be exported during the period of the licence of 86 200 000 cubic metres.

- b. to authorize new exports of gas at Aden, Alberta, for an eight-year period commencing 1 January 1980, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	1 Jan 80 - 31 Dec 84	1 416 400	283 300 000
	1 Jan 85 - 31 Dec 85	1 062 300	212 500 000
	1 Jan 86 - 31 Dec 86	708 200	141 600 000
	1 Jan 87 - 31 Dec 87	354 100	70 800 000

(ii) a total quantity that may be exported during the period of the licence of 1 841 400 000 cubic metres.

- c. to extend Licence GL-5 for one year commencing 31 October 1986, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	31 Oct 86 - 31 Oct 87	255 000	77 600 000

(ii) a total quantity that can be exported during the period of the extension of 77 600 000 cubic metres.

- d. to extend Licence GL-36 for two years commencing 1 November 1985, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	1 Nov 85 - 31 Oct 86	170 000	51 700 000
	1 Nov 86 - 31 Oct 87	85 000	25 900 000

(ii) a total quantity that can be exported during the period of the extension of 77 600 000 cubic metres.

- e. to vary Licences GL-5, GL-17, GL-25, and GL-36 to provide for the following:
- (i) the deletion of Aden as an authorized point of export for the four licences;
 - (ii) the variation of the current daily and annual exportable volumes under condition 2 now contained in Licences GL-5 and GL-36, having the effect in aggregate of reducing the maximum annual volume currently authorized under the four licences from $968.8 \times 10^6 \text{ m}^3$ (34.2 Bcf) to $827.2 \times 10^6 \text{ m}^3$ (29.2 Bcf), by reducing maximum daily and annual authorized volumes in the two licences to:

	<u>Daily</u> (m^3)	<u>Annual</u> (m^3)
GL-5	1 019 800	310 189 800
GL-17	679 900	206 793 200
GL-25 ⁽¹⁾	679 900	206 793 200
GL-36	339 900	103 396 600

- (iii) the revocation of conditions 7 and 8 of Licence GL-5;
- (iv) the revocation of conditions 5 and 6 of Licence GL-17;
- (v) the revocation of condition 6 of Licence GL-25; and
- (vi) the revocation of condition 6 of Licence GL-36.

9.4 Columbia

Columbia applied for a 15-year licence to authorize annual exports of $385.3^{(2)}$ million cubic metres of gas to be produced from the Kotaneelee Field in the Yukon. The gas would be transported from the Field to the export point at Huntingdon, B.C. by Westcoast. The proposed Columbia exports would go to its parent, Columbia Transmission, but would constitute less than one percent of its parent's general system requirements. Delivery of the gas in the United States would be effected largely by displacement through existing pipeline systems, although some new facilities would be required on the Northwest system. The Board sees further interconnections between El Paso and Northwest as beneficial in terms of widening the potential for gas exported over the Westcoast

(1) for the period ending 31 October 1991. After 31 October 1991, the licenced volumes reduce.

(2) $385.3 \times 10^6 \text{ m}^3$ is equivalent to $368.3 \times 10^6 \text{ m}^3$ at Huntingdon.

system, and believes that the Columbia export would contribute to the resolution of the load factor problem which has faced Westcoast with respect to Licence GL-41.

The Board does have some concern that contracts covering transportation arrangements for Columbia's gas have not been finalized, but, in light of the special circumstances regarding the development of the Kotaneelee Field, the Board is prepared to issue a licence to Columbia conditional upon the filing of the necessary executed contracts.

The Board notes the evidence of Columbia with respect to the investment needed to develop the Kotaneelee Field by Columbia and other producers in the Field, and is aware of the interrelationship between the capability to recover such investments and the length of assured access to markets for the gas a licence provides. However, the 15-year period requested extends well beyond that in which firm exports can be made under the Current Deliverability Test. The Board finds that Columbia's remaining established reserves are $4.5 \times 10^9 \text{ m}^3$, some $1.2 \times 10^9 \text{ m}^3$ less than the total export volume requested. In this regard, and taking into account the shortfall in Columbia's remaining established reserves vis-a-vis the total export volume requested, the Board concludes that the eight-year export period available under the Current Deliverability Test is the appropriate period for a licence to be issued to Columbia at this time.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board is not prepared to approve the term of the licence requested by Columbia. However, the Board is prepared to issue a licence as set out in Appendix H, and as summarized as follows:

to authorize new exports of gas at Huntingdon, British Columbia, for an eight-year period commencing 1 January 1980, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m^3)	<u>Annual</u> (m^3)
	1 Jan 80 - 31 Dec 84	1 110 400	368 300 000
	1 Jan 85 - 31 Dec 85	832 800	276 200 000
	1 Jan 86 - 31 Dec 86	555 200	184 200 000
	1 Jan 87 - 31 Dec 87	277 600	92 100 000

- (ii) a total quantity that may be exported during the period of the licence of 2 394 000 000 cubic metres.
- (iii) provided that, notwithstanding the date fixed for the commencement of deliveries under the licence, no exports may occur until the Board is satisfied that all requisite contracts for the purchase and transportation of the gas have been executed.

9.5 Niagara

Niagara applied for a new licence to authorize exports over a 16-year period. It sought, through a combination of its existing Licence GL-6 and a new licence, to be allowed to increase its existing export levels to a total of 1 200 000 cubic metres per day and 273 500 000 per year, and after Licence GL-6 expires during the 1984-85 contract year, to maintain its exports at those levels. Niagara has also applied for a condition in the licence that would permit it to export, in any 24-hour period, an amount that exceeds the daily allowable volume by two percent.

Niagara exports relatively small volumes of natural gas to a region of New York State that is entirely dependent upon Canadian gas, and which has no alternative source of gas supply within economic reach. The spectre was raised at the hearing that, without the extension of GL-6, Niagara would at a future date have to shut off its exports, leaving 10,000 people without a source of gas. However, increasing gas exports to this market only increases the number of United States citizens that could be directly affected if, in the future, further gas supplies from Canada were not available. Nevertheless, the Board notes that the volumes of gas involved are relatively small. While the Board believes exports of a border accommodation nature are consistent with the spirit of amity and comity that exists between Canada and the United States, the Board cautions that the issuance of a licence does not imply an unending obligation.

The proposed 16-year licence requested by Niagara would extend well beyond the period in which the Board is prepared to approve new licences under the Current Deliverability Test. The Board notes Niagara's argument that its customer requires a reasonable period of assured supply if it is to manage its operations in an orderly manner. At the same time, the Board is aware that Niagara's existing Licence GL-6 will expire sometime in the 1984-85 contract year.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board is not prepared to approve the term of the licence requested by Niagara. However, the Board is prepared to issue a licence as set out in Appendix H, and as summarized as follows:

to authorize new exports of gas at the international boundary near Cornwall, Ontario, for an eight-year period commencing 1 January 1980, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	1 Jan 80 - 31 Oct 80	350 000	89 100 000
	1 Nov 80 - 31 Oct 84	350 000	89 100 000
	1 Nov 84 - 31 Oct 85	262 500	66 800 000
	1 Nov 85 - 31 Oct 86	600 000	136 800 000
	1 Nov 86 - 31 Oct 87	300 000	68 400 000

(ii) a total quantity that may be exported during the period of the licence of 717 500 000 cubic metres.

(iii) a tolerance of two percent by which the Licensee may exceed the daily limitation:

9.6 ProGas

ProGas applied for a nine-year licence to export at Emerson 3 100 000 000 cubic metres per year for the first five years of the licence, with that quantity reducing by 20 percent in each of the last four years. ProGas also applied for a condition in the licence that would permit it to export, in any 24-hour period, an amount that exceeds the daily allowable volume by two percent. Its export proposal would entail the displacement of some of TransCanada's deliveries to Eastern Canada from the Great Lakes system to the TCPL Central Section, requiring the construction of additional facilities by TCPL.

The Board finds that ProGas has sufficient gas supplies under contract and that deliverability from ProGas's established reserves is adequate to serve the proposed export licence, except for a slight deficiency in 1981, which the Board attributes to field start-up problems.

The ProGas exports would constitute some two to three percent of the total supply available to ProGas's United States customers. ProGas proposed that its exports commence to phase out after five years, with TransCanada having the right to purchase the gas available as a result of the reduced exports. However, ProGas also proposed that it be granted the option of continuing the exports at the higher level if TransCanada should elect not to take these displaced volumes of gas.

The Board views favourably the concept of the phasing-out of exports, noting that it is consistent with the Board's decision and findings of the exportable surplus available under the Current Deliverability Test. However, it views the open-ended aspect of the application - that ProGas be allowed to export at a higher level in the phase-down period if TransCanada does not take the gas - as inconsistent with the Board's regulatory responsibilities, and hence not acceptable.

ProGas proposed to move its export volumes through the facilities of TransCanada, requiring an expansion of TransCanada's system, the magnitude and cost of which would be dependent on the overall requirements on the TCPL system and their rate of growth, including requirements to carry gas for other new exports arising from this hearing. The Board agrees there are some merits to the early expansion of TransCanada facilities that will later be useful to meet Canadian requirements, providing that such early expansion does not create undue unused capacity at a future period before Canadian requirements "catch up" to the higher capacity levels. The Board concludes that such would not be the case as a result of expansion necessary to carry the ProGas volumes, and indeed finds that the "prebuilding" of the TCPL system would be in the public interest.

ProGas and its United States customers also indicated their willingness to switch the ProGas volumes to the prebuilt facilities of Foothills, if the Board was to find that such an arrangement was in the public interest of Canada. If the companies do reach agreements for the transfer and transportation of the ProGas exports by Foothills, the Board would be prepared to consider amending ProGas's licence to allow for exports at Monchy, but only after it had first been satisfied that the transfer of volumes would not create undue surplus capacity on the TransCanada system.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board is not prepared to approve the term of the licence requested by ProGas. However, the Board is prepared to issue a licence as set out in Appendix H, and as summarized as follows:

to authorize new exports of gas at Emerson, Manitoba, for a seven-year period commencing 1 November 1980, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	1 Nov 80 - 31 Oct 84	9 440 900	3 100 000 000
	1 Nov 84 - 31 Oct 85	7 088 700	2 325 000 000
	1 Nov 85 - 31 Oct 86	4 720 400	1 550 000 000
	1 Nov 86 - 31 Oct 87	2 360 200	775 000 000
(ii)	a total quantity that may be exported during the period of the licence of 17 050 000 000 cubic metres.		
(iii)	a tolerance of two percent by which the Licensee may exceed the daily limitation.		

9.7 Sulpetro

Sulpetro applied to export 623 ⁽¹⁾ million cubic metres a year for three years to a point near Niagara Falls, Ontario. The gas would be transported to Niagara Falls via the facilities of TransCanada.

Sulpetro advocated that the main advantage of its application was that it allowed for some exports to start immediately, and that the exports would terminate just after the main Pan-Alberta exports via the Foothills eastern leg commenced, if the Foothills prebuilt facilities were completed on schedule.

(1) $623 \times 10^6 \text{ m}^3$ is equivalent to $612.8 \times 10^6 \text{ m}^3$ at Niagara.

The Board finds that Sulpetro has sufficient gas supply to meet the proposed export volumes, particularly in light of the fact that, in the initial period of exports, Sulpetro would be able to call upon gas available from Pan-Alberta to make up any deliverability shortfall arising through start-up problems in its own supply fields.

Decision

Having regard to all the evidence and to the Board's findings on surplus, the Board is prepared to issue a licence to Sulpetro as set out in Appendix H, and as summarized as follows:

to authorize new exports of gas at the international boundary near Niagara Falls, Ontario, for a three-year period commencing 1 January 1980, providing for the export of gas under the following conditions:

- | | | | |
|-----|----------------------|-----------------------------------|------------------------------------|
| (i) | <u>Period</u> | <u>Daily</u>
(m ³) | <u>Annual</u>
(m ³) |
| | 1 Jan 80 - 31 Oct 80 | 2 089 100 | 612 800 000 |
| | 1 Nov 80 - 31 Oct 82 | 2 089 100 | 612 800 000 |
- (ii) a total quantity that may be exported during the period of the licence of 1 838 400 000 cubic metres.

9.8 Westcoast

Westcoast filed three applications with the Board. One sought to extend Licence GL-4 to provide for an additional 5 693 895 840 cubic metres of gas to be exported during the period ending 31 October 1989. The second application sought to increase the total volume of gas authorized under Licence GL-41 by 18 382 559 800 cubic metres during the period 1 November 1989 to 31 October 1995. In a third application, Westcoast applied for authority to increase for the period 1 November 1980 to 31 October 1989 the daily maximum allowable exports under Licence GL-41 by 1 699 670 cubic metres and to increase the annual allowable exports by 620 379 700 cubic metres, but without increasing the total term quantity of exports now authorized in that period under Licence GL-41.

The Board is satisfied that between Westcoast's remaining reserves under AERCB Permit No. WC 59-3 and the firm gas volumes available to it from Pan-Alberta, Westcoast has sufficient gas reserves to supply the additional exports under the proposed extension to Licence GL-4.

As an associated issue, the Board notes British Columbia's policy to achieve as high a share of exports as possible for British Columbia production. As Westcoast intends to dedicate its Pan-Alberta contract gas to Licence GL-4 if the extension to GL-4 is granted, the diversion of this Alberta gas from exports at Huntingdon to Kingsgate would be consistent with British Columbia's policy objectives, by freeing up more capacity on the Westcoast mainline system for British Columbia gas.

The Board notes that the requested amendment to Licence GL-41, to increase the daily and annual maximum authorized volumes to provide for the El Paso sale, does not involve any increase in the term volumes of that licence during the period of the El Paso sale. Rather, Westcoast has sufficient gas volumes remaining unexported under the original level of authorizations in the licence to satisfy this amendment.

Concern has been expressed in the past for the low load factor under which gas has been exported under Licence GL-41. Should an improved level of take on the Westcoast system not result from the decision arising from this Hearing, the Board may give further consideration to resolving the matter.

Westcoast's three applications are to some degree interrelated. The evidence shows that if the extension of Licence GL-4 is not approved, offline sales by Northwest to Pacific Interstate would terminate because Northwest would have to adjust gas flows in its system to meet the requirements of customers in the Spokane, Washington area. In addition, new facilities to accommodate these new flow patterns would be required. The Board notes Westcoast's evidence that, if the above should be necessary, the new facilities required to enable the deliveries to El Paso to take place would become so complex and expensive as to render the purchase of gas unattractive to El Paso.

Westcoast stated that the extension of the expiry date of Licence GL-41 would facilitate the El Paso sale because, by enabling a contract for firm sales for a twelve-year period, the cost of amortizing

the new facilities required on the Northwest system could be spread out, making approval by FERC more likely. However, FERC approval for a nine-year contract period (to the end of Licence GL-41's present term) was thought possible.

With respect to the extension of GL-41, Westcoast believed it was desirable to provide some assurance to its United States customers that they would not be abruptly cut-off when GL-41 expired in 1989. Westcoast also believed the extension would encourage continued activity by British Columbia producers who otherwise might commence leaving the province well before 1989 if they perceived that Licence GL-41 would terminate at that time.

The Board concludes that the extension of Licence GL-4 would be in the public interest. The Board notes that it will require no new facilities, and that it will assist in the orderly marketing of British Columbia gas. The Board believes that the extension of the term of Licence GL-4 to make it consistent with the present term of Licence GL-41 would be advantageous from the viewpoint of orderly market arrangements. However, the Board does not believe the public interest dictates a treatment different from that accorded other Applicants; accordingly, it is prepared to authorize firm exports only under the Current Deliverability Test, with phased reductions in the authorized volumes commencing in 1985.

With regard to the proposed extension to Licence GL-41, the Board does not find it prudent to make judgements on the merits of licence extensions that will not go into effect for some ten years. While the Board concurs that the consideration of a licence extension should take place at a reasonable period of time before the licence expiry date, it finds that under present circumstances ten years is an excessive lead time, and in any event, is well outside the period of export covered by the Current Deliverability Test. The Board does note the advantages of the proposed tapering off of export volumes embodied in the Licence GL-41 extension application.

The amendment of the daily limits of Licence GL-41 to facilitate the El Paso contract appears to the Board to be desirable through the improvement it offers to the load factor problem associated with Licence GL-41. However, the Board believes that the annual averaging condition now contained in Licence GL-41 based on the level of currently-authorized maximums, provides Westcoast with sufficient annual volumes under this Licence to meet the requirements of the sale to El Paso. Therefore, the Board does not intend to increase the annual quantity that is currently authorized in the Licence. The Board recognizes that load factor difficulties may well persist even with the addition of firm volume sales to El Paso, but the Board believes that the El Paso sale would help to solve this problem. The Board concurs with the views put forward that it is not appropriate for the Board at this time to impose a "minimum take" condition on Licence GL-41.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board is not prepared to approve Westcoast's application for an extension to Licence GL-41, or to approve Westcoast's application for an increase in the current annual maximum volume authorization of Licence GL-41. Accordingly, Westcoast's application to extend the total volume authorized and the period of Licence GL-41 to provide for the export of 18 383 000 000 cubic metres during the period 1 November 1989 to 31 October 1995, and Westcoast's application to increase the current annual volume authorized from an average 7 970 300 000 cubic metres to 8 590 700 000 cubic metres, are both denied.

However while the Board is not prepared to approve the term of the extension requested for Licence GL-4, the Board is prepared to issue orders amending Licences GL-4 and GL-41 as set out in Appendix H, and as summarized as follows:

- a. to extend Licence GL-4 for six years providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	10 Dec 81 - 31 Oct 82	4 305 800	1 300 000 000
	1 Nov 82 - 31 Oct 84	4 305 800	1 444 700 000
	1 Nov 84 - 31 Oct 85	3 229 400	1 083 500 000
	1 Nov 85 - 31 Oct 86	2 152 900	722 400 000
	1 Nov 86 - 31 Oct 87	1 076 500	361 200 000
(ii)	a total quantity that may be exported during the period of the extension of 6 356 500 000 cubic metres.		

- b. to vary Licence GL-41, by:

- (i) providing for an increase in the daily maximum volume authorization, for a nine-year period commencing 1 November 1980, to 24 622 570 cubic metres; and
- (ii) amending the annual averaging clause to continue annual averaging based on the existing daily maximum rate of 22 922 900 cubic metres.

9.9 The Joint Applicants

As the licences the Board would issue to the Joint Applicants will be in the name of the individual companies involved, the Board prefers to set down its decision with respect to each company separately.

9.9.1 Pan-Alberta

Pan-Alberta applied for two 14-year licences, one to export 7 478 600 cubic metres a day at Kingsgate, and the other to export 24 928 500 cubic metres a day at Monchy. The total quantity of gas to be exported would be 139 880 607 700 cubic metres. In the event that the Board was not prepared to grant the full 14-year period, Pan-Alberta requested, as an alternative, firm export volumes totalling 67 030 468 200 cubic metres under two licences for the period ending 31 October 1987, and a further 72 850 139 500 cubic metres as conditional volumes for the remainder of the period to 31 October 1994, plus a deficiency make-up year to 31 October 1995. Pan-Alberta also applied for a condition in the licence that would permit it to export, in any 24-hour period, an amount that exceeds the daily allowable volume by two percent.

The Board concludes that the volume of Pan-Alberta's gas supply under contract and AERCB Permit No. PA 79-2, available to serve Pan-Alberta's various projects, is $117.7 \times 10^9 \text{ m}^3$. Although Pan-Alberta testified that it believes the initial proven reserves under contract to it were $168 \times 10^9 \text{ m}^3$ and that it had reapplied to AERCB for additional permit volumes, the Board believes that the potential for Pan-Alberta to secure additional permitted volumes must be weighed against the potential future new domestic obligations of Pan-Alberta, including the provision of gas to the Q & M pipeline, the sale to Pacific Northern once Alaskan gas begins to flow, and the incremental Alberta fuel and shrinkage volumes which are a function of total production. Furthermore, Pan-Alberta has some $15.5 \times 10^9 \text{ m}^3$ of remaining existing domestic commitments to service from its current reserves base. Accordingly, it is the Board's view that the gas which Pan-Alberta has available for dedication to both new Canadian projects and to exports is about $102.2 \times 10^9 \text{ m}^3$, less seven percent for fuel and shrinkage, which is considerably greater than the quantity of new exports the Board is prepared to authorize.

The Pan-Alberta export application is directly tied to the prebuilding of major new facilities by Foothills, by providing for the delivery of Canadian gas through the prebuilt facilities of the ANGTS on both sides of the international boundary for a period of at least several years, before Alaskan gas commences to flow. The Board has found that prebuilding of the Foothills pipeline system is in the public interest and that the export of Alberta gas through the prebuilt facilities until Alaska gas flows, would foster the financing of the whole project. Accordingly, the Board concludes that the issuance of licences to Pan-Alberta in which the quantities of gas to be exported conform with the quantities that can be allowed by the phase-down procedure adopted by the Board under the Current Deliverability Test, would not only be consistent with the public interest but also would be consistent with the treatment accorded other Applicants.

The Board is prepared to issue licences to Pan-Alberta on the understanding that the construction of prebuilt facilities will proceed expeditiously for completion of the western leg by November 1980 and the eastern leg by November 1981. Should this not take place it would be the intent of the Board to conduct a review of these licences under Section 17 of the Act.

The Board is not prepared to recommend the authorization of early exports by Pan-Alberta, to begin before the prebuilt facilities are completed. Accordingly, the Board will condition the Pan-Alberta licences so that they authorize the export through the prebuilt facilities of Foothills only.

With regard to Pan-Alberta's alternative request for a firm and conditional licence for a 15-year term, the Board finds that the proposed "show cause" condition is inconsistent with the Current Deliverability Test, and, in any event, is not a procedure which could be sanctioned under the NEB Act. The Board finds that the use of the Future Deliverability Test would not be appropriate to the circumstances of Pan-Alberta's exports. Hence, the Board is not prepared to grant conditional licences to the Company.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board is not prepared to approve the term of the licences requested by Pan-Alberta. However, the Board is prepared to issue licences as set out in Appendix H, and as summarized as follows:

- a. to authorize new exports of gas at Monchy, Saskatchewan, for a six-year period commencing 1 November 1981, providing for the export of gas under the following conditions:

- | (i) | <u>Period</u> | <u>Daily</u>
(m ³) | <u>Annual</u>
(m ³) |
|-----|----------------------|-----------------------------------|------------------------------------|
| | 1 Nov 81 - 31 Oct 84 | 24 928 500 | 8 294 400 000 |
| | 1 Nov 84 - 31 Oct 85 | 18 696 400 | 6 220 800 000 |
| | 1 Nov 85 - 31 Oct 86 | 12 464 300 | 4 147 200 000 |
| | 1 Nov 86 - 31 Oct 87 | 6 232 100 | 2 073 600 000 |
- (ii) a total quantity that may be exported during the period of the licence of 37 324 800 000 cubic metres.
- (iii) a tolerance of two percent by which the Licensee may exceed the daily limitation.
- (iv) a requirement that the gas to be exported be delivered through the pipeline systems of Foothills (Alta.) and Foothills (Sask.).

- b. to authorize new exports of gas at Kingsgate, B.C., for a seven-year period commencing 1 November 1980, providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	1 Nov 80 - 31 Oct 84	7 478 600	2 488 300 000
	1 Nov 84 - 31 Oct 85	5 608 900	1 866 200 000
	1 Nov 85 - 31 Oct 86	3 739 300	1 244 200 000
	1 Nov 86 - 31 Oct 87	1 869 900	622 100 000

- (ii) a total quantity that may be exported during the period of the licence of 13 685 700 000 cubic metres.
- (iii) a tolerance of two percent by which the Licensee may exceed the daily limitation.
- (iv) a requirement that the gas to be exported be delivered through the pipeline systems of Foothills (Alta.) and Foothills (South B.C.).

9.9.2 TransCanada

TransCanada applied for the extension of Licence GL-1, which is currently due to expire on 14 May 1981. However, before that date, TransCanada will have exported, by sometime in mid-1980, the full term volumes authorized. TCPL therefore sought authority to maintain the level of exports under the licence for the balance of the period it had contracted to sell gas to its customer, Midwestern. Accordingly, TCPL sought to export some 11 331 million cubic metres for the period from mid-1980 to 14 December 1985.

The Board is satisfied that TransCanada has adequate supply to meet the export volumes under its proposed extension to Licence GL-1.

The United States customers for the gas TCPL has been exporting under Licence GL-1 have been receiving Canadian gas for approximately 20 years and are largely dependent on Canada for their natural gas supply. The Board notes TransCanada's evidence that the discontinuation of Licence GL-1, even if alternative sources of gas could be obtained, would result in the idling of some pipeline facilities in Canada and the United States and would necessitate the construction of other facilities in the United States to connect the market to an alternative source. This would likely give rise to hardship in those regions through curtailments.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board finds that it would be in the public interest to approve the continuation of quantities currently being exported under Licence GL-1. However, the Board believes that it would be preferable, in light of the uncertainty regarding the date on which exports under Licence GL-1 will expire, to issue a new licence to TransCanada for the period 1 January 1980 to 14 December 1985, providing for the export of gas during the period, but taking into account the phase-down procedure adopted under the Current Deliverability Test. Accordingly, the Board is prepared to issue a new licence to TransCanada as set out in Appendix H, and as summarized as follows:

to authorize the exportation of gas at Emerson, Manitoba, for a five-year period commencing 1 January 1980 providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	1 Jan 80 - 31 Oct 80	6 317 100	800 000 000
	1 Nov 80 - 31 Oct 84	6 317 100	2 096 300 000
	1 Nov 84 - 31 Oct 85	4 737 800	1 572 200 000
	1 Nov 85 - 14 Dec 85	3 158 600	139 000 000

(ii) a total quantity that may be exported during the period of the licence of 10 896 400 000 cubic metres.

(iii) the total quantity of gas that may be exported during any one day during the period 1 January 1980 to 14 May 1981 may not exceed the difference between 6 317 100 cubic metres and the volume of gas exported under Licence GL-1 on that day.

9.9.3 Consolidated

Consolidated applied to export an average annual volume of 2 068 million cubic metres for a five-year period, followed by a phased reduction in exports of 20 percent per year for a further four years. It proposed to commence exports at Emerson via the TransCanada system, with the option to transfer its gas volumes to the prebuilt facilities of Foothills, for export at Monchy. As an alternative, Consolidated requested a licence for firm exports for five years if the Board was not disposed to grant the full nine-year period applied for. Consolidated applied for a condition in the licence that would permit it to export, in any 24-hour period, an amount that exceeds the daily allowable volume by two percent.

After considering the evidence relative to Consolidated's natural gas supplies, the Board is satisfied that Consolidated has adequate remaining established reserves to supply the proposed exports. Consolidated's exports could assist from time to time in relieving TCPL's take-or-pay obligation. Consolidated indicated that the proposed export would not require new facilities on the TransCanada system. It further testified that it was willing to switch its throughput to the prebuilt facilities of Foothills upon their completion.

The Board views the tapering off of Consolidated's proposed exports as a commendable concept. The Board notes that while the export of Consolidated's volume alone may not require new facilities, the transportation of Consolidated's volume in addition to other proposed new exports could entail expansion of the TransCanada system. The proposed switch of Consolidated's gas from TransCanada to Foothills could, therefore, serve to relieve the early need for new facilities additions on the TCPL system if it occurs in the relatively near future. If the construction of the Foothills facilities is delayed, however, therefore requiring the expansion of TransCanada's system to provide continued capacity for the Consolidated gas, it may be desirable to continue the movement of the Consolidated gas in the TCPL system until such time as other requirements need the capacity that had been provided to accommodate Consolidated. At that time, Consolidated could switch to Foothills.

Accordingly, in light of the uncertainty concerning the impact of the switch of Consolidated's gas from TransCanada to Foothills, the Board is not prepared to authorize an automatic change of export point. Any subsequent application for change of point of export from Emerson to Monchy should be supported by evidence that the switching of its gas from TransCanada to Foothills will not cause a large dislocation on the TCPL system.

Consistent with its views with respect to other export applications, the Board considers the term requested by Consolidated should be restricted to the period of surplus covered by the Current Deliverability Test.

Decision

Having regard to all of the evidence and to the Board's findings on surplus, and to the decision to permit exports at reduced levels during the period 1985 to 1987 resulting from application of the Current Deliverability Test, the Board is not prepared to approve the term of the licence requested by Consolidated. However, the Board is prepared to issue a licence as set out in Appendix H, and as summarized as follows:

- a. to authorize new exports of gas at Emerson, Manitoba, for a seven-year period commencing 1 November 1980 providing for the export of gas under the following conditions:

(i)	<u>Period</u>	<u>Daily</u> (m ³)	<u>Annual</u> (m ³)
	1 Nov 80 - 31 Oct 84	5 665 600	2 067 900 000
	1 Nov 84 - 31 Oct 85	4 249 200	1 551 000 000
	1 Nov 85 - 31 Oct 86	2 832 800	1 034 000 000
	1 Nov 86 - 31 Oct 87	1 416 400	517 000 000

- (ii) a total quantity that may be exported during the period of the licence of 11 373 600 000 cubic metres.
- (iii) a tolerance of two percent by which the Licensee may exceed the daily limitation.

9.10 Summary

As a result of the within decisions, the Board will recommend to the Governor in Council the approval of ten new licences, and orders for the amendment of nine existing licences, which it is prepared to issue.

New licences will be issued to the following Applicants, subject to the approval of the Governor in Council:

<u>Company</u>	<u>Export Point</u>
Canadian-Montana	Aden, Alberta
Canadian-Montana	Cardston, Alberta
Columbia	Huntingdon, B.C.
Niagara	Cornwall, Ontario
ProGas	Emerson, Manitoba
Sulpetro	Niagara Falls, Ontario
Pan-Alberta (Western export)	Kingsgate, B.C.
Pan-Alberta (Eastern export)	Monchy, Saskatchewan
TransCanada	Emerson, Manitoba
Consolidated	Emerson, Manitoba

Similarly, the Board's decision will require the amendment of the following licences:

<u>Company</u>	<u>Licence No.</u>
Alberta and Southern	GL-3, GL-35
Canadian-Montana	GL-5, GL-17, GL-25, GL-36
Westcoast	GL-4, GL-41

In summary, the Board's decision will result in the authorization of the following new gas exports, subject to the approval of the Governor in Council:

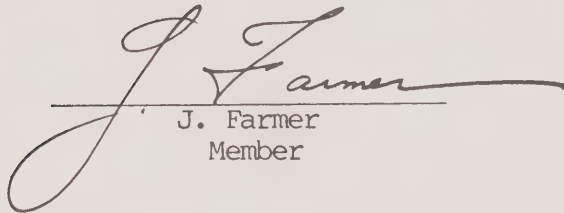
<u>Company</u>	<u>New Export Volume</u>		
	(m ³)	(PJ)	(Bcf)
Alberta and Southern	2 519 700 000	97.6	88.9
Canadian-Montana	2 082 800 000	77.0	73.5
Columbia	2 394 000 000	93.1	84.5
Niagara	717 500 000	27.2	25.3
ProGas	17 050 000 000	645.6	601.9
Sulpetro	1 838 400 000	69.6	64.9
Westcoast	6 356 500 000	246.2	224.4
Pan-Alberta	51 010 500 000	1 991.9	1,800.7
TransCanada	10 896 400 000	411.7	384.6
Consolidated	11 373 600 000	430.7	401.5
TOTAL	106 239 400 000	4 090.6	3,750.2

* * * * *

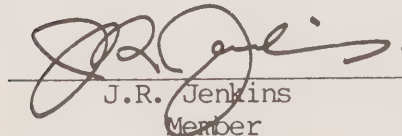
The foregoing chapters set forth our Reasons for
Decision and our Decision in this matter.



J.G. Stabback
Presiding Member



J. Farmer
Member



J.R. Jenkins
Member

NATIONAL ENERGY BOARD



OFFICE NATIONAL DE L'ÉNERGIE

ORDER NO. GH-4-79

IN THE MATTER OF the National Energy Board Act
and the Regulations made thereunder;

AND IN THE MATTER OF applications made by Alberta
and Southern Gas Co. Ltd., Canadian-Montana Pipe
Line Company, Columbia Gas Development of Canada
Ltd., ICG Transmission Limited, Niagara Gas
Transmission Limited, ProGas Limited, Sulpetro
Limited, and Westcoast Transmission Company Limited
for licences under Part VI of the National Energy
Board Act for the export of natural gas to the
United States of America;

AND IN THE MATTER OF a joint application made by
Pan-Alberta Gas Ltd., TransCanada PipeLines Limited,
and Consolidated Natural Gas Limited for licences
under Part VI of the National Energy Board Act for the
export of gas to the United States of America;

AND IN THE MATTER OF applications by Q & M Pipe
Lines Ltd., TransCanada PipeLines Limited, and ICG
Transmission Limited for certificates of public
convenience and necessity under Part III of the
National Energy Board Act;

B E F O R E the Board on Monday, the 7th day of May, 1979.

UPON Alberta and Southern Gas Co. Ltd.,
hereinafter referred to as "Alberta and Southern", having
filed with the Board an application dated the 5th day of
April, 1979, for a licence under Part VI of the National
Energy Board Act authorizing the export of natural gas at a
point on the international boundary between Canada and the
United States of America near Kingsgate, in the Province of
British Columbia;

AND UPON Canadian-Montana Pipe Line Company,
hereinafter referred to as "Canadian-Montana", having filed
with the Board applications dated the 21st day of March,
1979, and the 21st day of April, 1979, for licences under
Part VI of the National Energy Board Act authorizing the
export of natural gas at points on the international boundary
between Canada and the United States of America near Aden and
Cardston, in the Province of Alberta;

AND UPON Columbia Gas Development of Canada Ltd.,
hereinafter referred to as "Columbia", having filed with the
Board an application dated the 2nd day of April, 1979, for a
licence under Part VI of the National Energy Board Act to

- 2 -

export natural gas at a point on the international boundary between Canada and the United States of America near Huntingdon, in the Province of British Columbia;

AND UPON ICG Transmission Limited, hereinafter referred to as "ICG", having filed with the Board an application dated the 30th day of March, 1979, for a certificate of public convenience and necessity under Part III of the National Energy Board Act, and for a licence under Part VI of the National Energy Board Act to export natural gas at a point on the international boundary between Canada and the United States of America near Fort Frances, in the Province of Ontario;

AND UPON Niagara Gas Transmission Limited, hereinafter referred to as "Niagara", having filed with the Board an application dated the 24th day of April, 1979, for a licence under Part VI of the National Energy Board Act to export natural gas at a point on the international boundary between Canada and the United States of America near Cornwall, in the Province of Ontario;

AND UPON ProGas Limited, hereinafter referred to as "ProGas", having filed with the Board an application dated the 26th day of February, 1979, for a licence under Part VI of the National Energy Board Act to export natural gas at a point on the international boundary between Canada and the United States of America near Emerson, in the Province of Manitoba;

AND UPON Sulpetro Limited, hereinafter referred to as "Sulpetro", having filed with the Board an application dated the 13th day of June, 1978, for a licence under Part VI of the National Energy Board Act to export natural gas at a point on the international boundary between Canada and the United States of America near Niagara Falls, in the Province of Ontario;

AND UPON Westcoast Transmission Company Limited, hereinafter referred to as "Westcoast" having filed with the Board applications dated the 30th day of April, 1979, for licences under Part VI of the National Energy Board Act to export natural gas at points on the international boundary between Canada and the United States of America near Kingsgate and Huntingdon, in the Province of British Columbia;

AND UPON Pan-Alberta Gas Ltd., TransCanada PipeLines Limited, and Consolidated Natural Gas Limited, hereinafter referred to jointly as, "Pan-Alberta, TCPL, and Consolidated", having filed with the Board a joint

- 3 -

application dated the 4th day of May, 1979, for licences to export natural gas at points on the international boundary between Canada and the United States of America, which joint application replaced the individual application sections of the March 26, 1979, filing of Pan-Alberta, the January 25, 1979, filing of TCPL, and the March 28, 1979, filing of Consolidated, but which joint application is supported by the materials filed with the individual applications listed;

AND UPON Q & M Pipe Lines Ltd., hereinafter referred to as "Q & M", having filed with the Board an application dated the 20th day of October, 1978, for a certificate of public convenience and necessity under Part III of the National Energy Board Act;

AND UPON TransCanada PipeLines Limited, hereinafter referred to as "TCPL", having filed with the Board an application dated the 4th day of April, 1978, as amended by an application dated the 27th day of April, 1979, for a certificate of public convenience and necessity under Part III of the National Energy Board Act;

IT IS HEREBY ORDERED THAT:

1. The above-noted applications shall be heard together at a public hearing in the Hearing Room of the National Energy Board, 473 Albert Street, in the City of Ottawa, in the Province of Ontario, commencing on Tuesday, the 10th day of July, 1979, at 9:30 a.m. local time and continuing in such other places and at such other times as the National Energy Board may direct. Such proceedings will be conducted in either of the two official languages and simultaneous interpretation will be provided should a party to the proceedings request such facilities in his intervention.
2. In the first phase of the hearing, to be referred to as the "Licence Phase", the Board will hear the evidence respecting the applications for licences for the export of natural gas made under Part VI of the National Energy Board Act and the application by ICG for a certificate of public convenience and necessity under Part III of the Act. The second phase of the hearing, to be referred to as the "Certificate Phase", will consider the applications of Q & M and TCPL for certificates of public convenience and necessity under Part III of the Act. Procedural orders will be issued by the Board with respect to the conduct of the hearing.
3. The Applicants shall arrange among them to have the Notice of Hearing in the form prescribed by the Board as set forth in the Notice attached hereto and which forms part

- 4 -

of this Order, published not later than the 25th day of May, 1979, in one issue each of the "Times" and the "Colonist" in the City of Victoria, in the Province of British Columbia; the "Herald" in the City of Calgary and the "Journal" in the City of Edmonton, in the Province of Alberta; the "Leader Post" in the City of Regina and the "Star-Phoenix" in the City of Saskatoon, in the Province of Saskatchewan; the "Free Press" in the City of Winnipeg, in the Province of Manitoba; the "Citizen" and "Le Droit" in the City of Ottawa, and the "Globe and Mail" and the "Financial Post" in the City of Toronto, in the Province of Ontario; "Le Devoir", the "Gazette", "La Presse", and the "Financial Times of Canada", in the City of Montreal, and "Le Soleil" in the City of Quebec, in the Province of Quebec; the "Telegraph Journal" in the City of Saint John and the "Gleaner" in the City of Fredericton, in the Province of New Brunswick; the "Chronicle Herald" in the City of Halifax, in the Province of Nova Scotia, the "Guardian" in the City of Charlottetown, in the Province of Prince Edward Island; the "Telegram" in the City of St. John's, in the Province of Newfoundland; the "Star" in the Town of Whitehorse, in the Yukon Territory; the "News of the North" in the Town of Yellowknife, in the Northwest Territories; and as soon as possible in the Canada Gazette.

4. Notice of the hearing shall forthwith be given by each of the applicants, by service of a true copy of this Order together with a copy of the application filed, upon the Attorneys General of all of the provinces of Canada; the British Columbia Energy Commission; the Energy Resources Conservation Board of Alberta; the Ontario Energy Board; Régie de l'électricité et du gaz du Québec; and the Canadian Federation of Agriculture.

5. Any respondent or intervenor intending to oppose or intervene in the hearing shall file on or before the 8th day of June, 1979, with the Secretary of the Board, thirty-five (35) copies of a written statement, in either of the two official languages, containing his reply or submission, together with any supporting information, particulars, or documents, which shall contain a concise statement of the facts from which the nature of the respondent's or intervenor's interest in the proceedings may be determined; which shall indicate whether the respondent or intervenor is interested in intervening in both phases of the hearing or only in the Licence Phase or in the Certificate Phase; which may admit or deny any or all of the facts alleged in any of the applications in which the intervenor is interested; which shall be endorsed with the name and address of the respondent or intervenor or his solicitor to whom

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- 5 -

communications may be sent; and which shall state in which of the two official languages the party wishes to be heard. Any respondent or intervenor shall, in addition, serve, on or before the 8th day of June, 1979, three (3) copies of his reply or submission and supporting information, upon each of the Applicants in the phase or phases in which he is interested and one (1) copy upon each of the parties named in paragraph 4 of this Order.

6. Any interested party may examine all of the applications at the offices of the National Energy Board, Trebla Building, 473 Albert Street, in the City of Ottawa, in the Province of Ontario, and 205 Fifth Avenue S.W., Room 3020, Bow Valley Square II, in the City of Calgary, in the Province of Alberta, and individual applications of the respective applicants at the following addresses:

Alberta and Southern Gas Co. Ltd.,
Alberta and Southern Building,
240 Fourth Avenue S.W.,
Calgary, Alberta.
T2P 0H5

Canadian-Montana Pipe Line Company,
4th Floor,
Humford Building,
608 - Seventh Street S.W.,
Calgary, Alberta.
T2P 1Z1

Columbia Gas Development of Canada Ltd.,
1000 Standard Life Building,
639 - 5th Avenue S.W.,
Calgary, Alberta.
T2P 0M9

Consolidated Natural Gas Limited,
1300 Elveden House,
717-7th Avenue S.W.,
Calgary, Alberta.
T2P 0Z3

ICG Transmission Limited,
Inter-City Gas Building,
1800 - 444 St. Mary Avenue,
Winnipeg, Manitoba.
R3C 3T7

Niagara Gas Transmission Limited,
Suite 4200,
P.O. Box 90,
1 First Canadian Place,
Toronto, Ontario.
M5X 1C5

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- 6 -

Pan-Alberta Gas Ltd.,
350, 202 Sixth Avenue S.W.,
Calgary, Alberta.
T2P 2R9

ProGas Limited,
#820, 444-5th Avenue S.W.,
Calgary, Alberta.
T2P 2V1

Sulpetro Limited,
3300 Bow Valley Square 2,
205 Fifth Avenue S.W.,
Box 9115,
Calgary, Alberta.
T2P 2W4

Westcoast Transmission Company Limited,
1333 West Georgia Street,
Vancouver, British Columbia.
V6E 3K9

Q & M Pipe Lines Ltd.,
202 Sixth Avenue S.W.,
1710 Bow Valley Square One,
P.O. Box 2535,
Calgary, Alberta.
T2P 2N6

or

Q & M Pipe Lines Ltd.,
620 Crown Trust Building,
1130 Sherbrooke Street West,
Montreal, Quebec.
H3A 2M8

TransCanada PipeLines Limited,
P.O. Box 54,
Commerce Court West,
Toronto, Ontario.
M5L 1C2

In addition, any interested party may examine the
applications for certificates of public convenience and
necessity of Q & M and TCPL at the following locations:

Quebec Public Service Board,
2875 Laurier Boulevard,
Quebec, Quebec.
G1A 1G8

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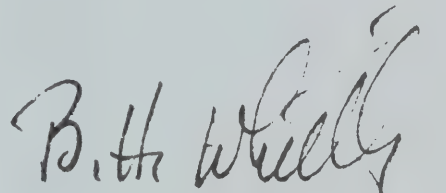
- 7 -

Board of Commissioners of Public Utilities,
110 Charlotte Street,
Saint John, New Brunswick.
E2L 2J4

Board of Commissioners of Public Utilities,
1526 Dresden Row,
Halifax, Nova Scotia.
B3J 3G7

DATED at the City of Ottawa, in the Province of
Ontario, this 7th day of May, 1979.

NATIONAL ENERGY BOARD

A handwritten signature in dark ink, appearing to read "B. H. Whittle", is written over a horizontal line.

Brian H. Whittle,
Secretary.

NATIONAL ENERGY BOARD
NOTICE OF HEARING

TAKE NOTICE that pursuant to the National Energy Board Act and Regulations made thereunder, the Board has ordered a hearing to be held in the Hearing Room of the National Energy Board, Trebla Building, 473 Albert Street, in the City of Ottawa, in the Province of Ontario, on Tuesday, the 10th day of July, 1979, commencing at the hour of 9:30 a.m. local time, and at such other places and at such times as the Board may direct to hear the applications of Alberta and Southern Gas Co. Ltd., Canadian-Montana Pipe Line Company, Columbia Gas Development of Canada Ltd., ICG Transmission Limited, Niagara Gas Transmission Limited, ProGas Limited, Sulpetro Limited, Westcoast Transmission Company Limited, and the joint application of Pan-Alberta Gas Ltd., TransCanada PipeLines Limited, and Consolidated Natural Gas Limited for licences under Part VI of the National Energy Board Act for the export of natural gas to the United States of America; and to hear the applications of Q & M Pipe Lines Ltd., TransCanada PipeLines Limited, and ICG Transmission Limited, for certificates of public convenience and necessity under Part III of the National Energy Board Act to construct and operate pipeline facilities. Such proceedings will be conducted in either of the two official languages and simultaneous interpretation will be provided should a party to the proceedings request such facilities in his intervention.

AND THE BOARD HAS FURTHER ORDERED THAT:

1. In the the first phase of the hearing, to be referred to as the "Licence Phase", the Board will hear evidence respecting the applications for licences for the export of natural gas made under Part VI of the National Energy Board Act and the application by ICG Transmission Limited for a certificate of public convenience and necessity under Part III of the Act. The second phase of the hearing, to be referred to as the "Certificate Phase", will consider the applications of Q & M and TransCanada for certificates of public convenience and necessity under Part III of the Act. Procedural orders will be issued by the Board with respect to the conduct of the hearing.

2. Any respondent or intervenor intending to oppose or intervene in the hearing shall file on or before the 8th day of June, 1979, with the Secretary of the Board, thirty-five (35) copies of a written statement, in either of the two official languages, containing his reply or submission, together with any supporting information, particulars, or documents, which shall contain a concise statement of the facts from which the nature of the respondent's or intervenor's interest in the proceedings may be determined; which shall indicate whether the respondent or intervenor is interested in intervening in both phases of the hearing or only in the Licence Phase or in the Certificate Phase; which may admit or deny any or all of the facts

- 2 -

alleged in any of the applications in which the intervenor is interested; which shall be endorsed with the name and address of the respondent or intervenor or his solicitor to whom communications may be sent; and which shall state in which of the two official languages the party wishes to be heard. Any respondent or intervenor shall, in addition, serve, on or before the 8th day of June, 1979, three (3) copies of his reply or submission and supporting information upon each of the Applicants in the phase or phases of the hearing in which he is interested and one (1) copy each upon the Attorneys General of all of the provinces of Canada; the British Columbia Energy Commission; the Energy Resources Conservation Board of Alberta; the Ontario Energy Board; Régie de l'électricité et du gaz du Québec; and the Canadian Federation of Agriculture.

3. Any interested party may examine all of the applications at the offices of the National Energy Board, Trebla Building, 473 Albert Street, in the City of Ottawa, in the Province of Ontario, and 205 Fifth Avenue S.W., Room 3020, Bow Valley Square II, in the City of Calgary, in the Province of Alberta, and individual applications of the respective Applicants at the following addresses:

Alberta and Southern Gas Co. Ltd.,
Alberta and Southern Building,
240 Fourth Avenue S.W.,
Calgary, Alberta.
T2P 0H5

Canadian-Montana Pipe Line Company,
4th Floor,
Humford Building,
608 - Seventh Street S.W.,
Calgary, Alberta.
T2P 1Z1

Consolidated Natural Gas Limited,
1300 Elveden House,
717-7th Avenue S.W.,
Calgary, Alberta.
T2P 0Z3

Columbia Gas Development of Canada Ltd.,
1000 Standard Life Building,
639 - 5th Avenue S.W.,
Calgary, Alberta.
T2P 0M9

ICG Transmission Limited,
Inter-City Gas Building,
1800 - 444 St. Mary Avenue,
Winnipeg, Manitoba.
R3C 3T7

Niagara Gas Transmission Limited,
Suite 4200,
P.O. Box 90,
1 First Canadian Place,
Toronto, Ontario.
M5X 1C5

ProGas Limited,
#820, 444-5th Avenue S.W.,
Calgary, Alberta.
T2P 2V1

Pan-Alberta Gas Ltd.,
350, 202 Sixth Avenue S.W.,
Calgary, Alberta.
T2P 2R9

Sulpetro Limited,
3300 Bow Valley Square 2,
205 Fifth Avenue S.W.,
Box 9115,
Calgary, Alberta.
T2P 2W4

Westcoast Transmission Company Limited,
1333 West Georgia Street,
Vancouver, British Columbia.
V6E 3K9

Q & M Pipe Lines Ltd.,
202 Sixth Avenue S.W.,
1710 Bow Valley Square One,
P.O. Box 2535,
Calgary, Alberta.
T2P 2N6

or
Q & M Pipe Lines Ltd.,
620 Crown Trust Building,
1130 Sherbrooke Street West,
Montreal, Quebec.
H3A 2M8

TransCanada PipeLines Limited,
P.O. Box 54,
Commerce Court West,
Toronto, Ontario.
M5L 1C2

In addition, any interested party may examine the applications for certificates of public convenience and necessity of Q & M and TransCanada at the following locations:

Quebec Public Service Board,
2875 Laurier Boulevard,
Quebec, Quebec.
G1A 1G8

Board of Commissioners of Public Utilities,
110 Charlotte Street,
Saint John, New Brunswick.
E2L 2J4

Board of Commissioners of Public Utilities,
1526 Dresden Row,
Halifax, Nova Scotia.
B3J 3G7

DATED at the City of Ottawa, in the Province of
Ontario, this 7th day of May, 1979.

NATIONAL ENERGY BOARD

Brian H. Whittle,
Secretary.

LIST OF INTERVENORS
TO LICENCE PHASE

Indicated Support
of Applications
(where given)

A. ASSOCIATIONS

Canadian Gas Association	---
Canadian Petroleum Association	---
Independent Petroleum Association of Canada	---
Industrial Gas Users Association	---

B. PRODUCERS

Alamo Petroleum Ltd.	Joint Applicants
Alberta Professional Leasing Ltd	" "
Algas Mineral Enterprises Ltd.	" "
American Eagle Petroleum Ltd.	" "
Amoco Canada Petroleum Company Ltd.	---
Anadarko Petroleum of Canada Ltd.	Joint Applicants
Anderson Exploration Ltd.	" "
Aquitaine Company of Canada Ltd.	Joint Applicants and Sulpetro
Argo Petroleum Corporation	Joint Applicants
BMC Resources Ltd.	" "
Blake Mineral Resources Ltd.	" "
Bow Valley Exploration	" "
Bralorne Resources Limited	" "
Brascan Resources Limited	Joint Applicants and Sulpetro
Bravo Resources Ltd.	Joint Applicants
Brenda Mines Ltd.	Sulpetro

Indicated Support
of Applications
(where given)

Brunswick Resources Ltd.	Joint Applicants	
Buttes Resources Canada, Ltd.	"	"
Calto Development Limited	"	"
Camflo Mines Limited	"	"
Canada-Cities Service, Ltd.	"	"
Canadian Homestead Oils Limited	Joint Applicants and Sulpetro	
Canadian Hunter Exploration Ltd.	"	"
Canadian Occidental Petroleum Ltd.	Joint Applicants	
Canadian Reserve Oil and Gas Ltd.	"	"
Canadian Superior Oil Ltd.	--	
Cardo Canada Limited	Joint Applicants	
CCH Resources Ltd.	"	"
Chevron Standard Limited	"	"
Chieftain Development Co. Ltd.	"	"
Chieftain International, Inc.	"	"
Cimarron Petroleum Ltd.	"	"
Coseka Resources Limited	"	"
DeKalb Petroleum Corporation	"	"
Delta Consultants (1973) Ltd.	"	"
Delta Western Funds, Inc.	"	"
Denison Mines Limited	"	"
Dome Petroleum Limited	"	"
Dorchester Exploration, Inc.	"	"
Eason Petroleum Limited	"	"
Entex Petroleums Ltd.	"	"
Fairweather Gas Ltd.	"	"
Flamingo Oils Limited (N.P.L.)	"	"
Fortress Exploration Ltd.	"	"
Francana Oil & Gas Ltd.	"	"
Frobisher Petroleums Ltd.	"	"

	<u>Indicated Support of Applications (where given)</u>	
Gas Initiatives Venture Ltd.	"	"
Gascan Resources Ltd.	"	"
Gascome Oils Ltd.	"	"
Getty Oil (Canada), Ltd.	"	"
Globe Oil Co. (1958) Ltd.	"	"
Gulf Canada Limited and Gulf Canada Resources Inc.	---	
Gull Oil & Gas Ltd.	Joint Applicants	
Habco Sales Ltd.	"	"
Hamilton Brothers Canadian Gas Company Ltd.	"	"
Hershey Oil Corporation	"	"
Hewitt Oil (Alberta) Ltd.	"	"
Highfield Oil and Gas Ltd.	"	"
Home Oil Company Limited	Joint Applicants and ProGas	
Horizon Oil & Gas Co. of Calgary (Calder) No. 4	Joint Applicants	
Horizon Oil & Gas Co. of Texas, Trustee	"	"
Hudson's Bay Oil & Gas Company Limited	---	
Husky Oil Operations Ltd.	Joint Applicants	
Imperial Oil Limited	---	
Inter-City Gas Limited, Exploration Division	Joint Applicants	
International Mogul Mines Limited	"	"
International Tika Resources Ltd.	"	"
J.S.E. Enterprises Ltd.	"	"
Kaiser Oil Ltd.	"	"
Kanata Gas & Oil Ltd.	"	"
Kandex Resources & Development Ltd.	"	"
Kissinger Petroleums Ltd.	"	"

Indicated Support
of Applications
(where given)

Landbank Minerals Ltd.	"	"
Lario Oil & Gas Company	"	"
LL & E Canada, Ltd.	"	"
Lochiel Exploration Ltd.	"	"
Loon River Oils Limited	"	"
Mannville Resources Ltd.	"	"
Marline Oil Corporation	"	"
Maynard Exploration Company	"	"
Medcon Petroleum Ltd.	"	"
Mesa Petroleum (N.A.) Co.	Pan-Alberta and Sulpetro	
Mizel Oils Ltd.	Joint Applicants	
Mobil Oil Canada, Ltd.	--	
Mohawk Oil Co. Ltd.	Joint Applicants	
Nicor Resources Ltd.	"	"
Norcen Energy Resources Limited	--	
Norpet Oil & Gas Ltd.	Joint Applicants	
Norseman Mines Limited (NPL)	"	"
North Canadian Oils Limited	"	"
Oakwood Petroleums Ltd.	"	"
Orient Investments Ltd.	"	"
The Paddon Hughes Development Co. Ltd.	"	"
Paloma Petroleum Ltd.	"	"
PanCanadian Petroleum Limited	Joint Applicants and ProGas	
Paramount Resources Ltd.	Joint Applicants	
Petrex Energy Limited	Joint Applicants	
Petro-Canada	--	
Petro Can Oil & Gas Corporation Ltd.	Joint Applicants	
Petrodyne Ltd.	"	"
Petrofina Canada Ltd.	"	"

Appendix B

Page 5 of 8Indicated Support
of Applications
(where given)

Petrogas Processing Ltd.	Westcoast
The Petrol Oil & Gas Company Limited	Joint Applicants
Phillips Petroleum Company Western Hemisphere	" "
Plains Petroleums Limited	Joint Applicants and Sulpetro
Provident Resources Ltd.	Joint Applicants
Quasar Petroleum Ltd.	" "
Quitana Exploration Co.	" "
Renaissance Resources Ltd.	" "
Resman Holdings Ltd.	" "
Ridgewood Resources Ltd.	" "
Riva Oil & Gas Ltd.	" "
Roger M. Gordon Land Services Ltd.	" "
Rupertsland Resources Limited	" "
Sachem Exploration Ltd.	" "
Sceptre Oils Ltd.	" "
Scurry-Rainbow Oil Limited	Joint Applicants and Sulpetro
Shell Canada Resources Limited	--
Shelter Oil & Gas Ltd., and Cree Lake Mining Ltd. (N.P.L.)	Joint Applicants
Signalta Resources Limited	" "
Simcoe Resources Ltd.	" "
Siscoe Metals of Ontario Limited	" "
Skye Resources (Alberta) Ltd.	" "
Southland Royalty Company	" "
Star Oil & Gas Ltd.	" "
Texaco Canada Inc.	Sulpetro

Indicated Support
of Applications
(where given)

	Joint Applicants	
Total Petroleum (North America) Ltd.		
Touche, Thomson & Yeoman Investment Consultants Ltd.	"	"
Trend Exploration Limited	"	"
Turbo Resources Limited	"	"
Union Oil Company of Canada Limited	"	"
Uno-Tex Petroleum Corporation	"	"
Vel Resources Ltd.	"	"
Vigas Propane Ltd.	"	"
Viking Oil & Gas Ltd.	"	"
Wainoco Oil & Gas Limited	"	"
Westcoast Petroleum Ltd.	"	"
Western Decalta Petroleum (1977) Limited	"	"
Wintershall Oil of Canada Ltd.	"	"
Zephyr Resources Ltd.	"	"

C. U.S. CUSTOMERS

Great Lakes Gas Transmission Company	--	
Michigan Wisconsin Pipe Line Company	ProGas and TransCanada	
Midwestern Customer Group	TransCanada	
Midwestern Gas Transmission Company	"	"
Minnesota Public Service Commission	--	
Natural Gas Pipeline Company of America	ProGas	
Northern Natural Gas Company	Joint Applicants	
North Dakota Public Service Commission	TransCanada	
Northwest Alaskan Pipeline Company	Joint Applicants	
Northwest Pipeline Corporation	--	
Pacific Interstate Transmission Company	Joint Applicants	
Pacific Lighting Exploration Company	"	"

Indicated Support
of Applications
(where given)Tennessee Gas Pipeline Company Division
of Tenneco Inc.

ProGas

Texas Eastern Transmission Corporation

"

Washington Natural Gas Company

Westcoast

D. OTHER COMPANIES

Alberta Gas Trunk Line Company Limited

Joint Applicants

British Columbia Hydro & Power Authority

--

Dow Chemical of Canada, Limited

--

Gaz Métropolitain, inc.

--

Greater Winnipeg Gas Company

--

Inland Natural Gas Co. Ltd.

--

Interprovincial Steel and Pipe
Corporation Ltd.

Joint Applicants

Northern and Central Gas
Corporation Limited

--

Pembina Pipe Line Ltd.

Joint Applicants

Polar Gas Limited

--

Public Utilities Commission of the
City of Kingston

--

Q & M Pipe Lines Ltd.

--

The Consumers' Gas Company

Niagara

Union Gas Limited

--

E. PUBLIC INTEREST GROUPS AND OTHERS

Canadian Arctic Resources Committee

--

New Democratic Party

--

Indicated Support
of Applications
(where given)

F. PROVINCIAL GOVERNMENTS

Attorney-General of the Province of British Columbia	--
Attorney-General of the Province of Manitoba	--
Province of Nova Scotia, Nova Scotia Energy Council	--
Ministry of Energy for Ontario	--
Procureur Général du Québec Ministère des Richesses Naturelles	--
The Department of Mineral Resources of the Government of Saskatchewan	--

NEB FORECAST OF TOTAL ENERGY DEMAND
AND
NATURAL GAS REQUIREMENTS

Introduction

As an integral part of the Licence Phase of this Hearing, the Board has reviewed its 1979 Gas Report forecast of energy demand. In the light of this reassessment, and in consideration of the evidence presented, the Board has concluded (as discussed in Chapter 4) that it will employ the forecast in the 1979 Gas Report for purposes of determining the surplus volumes of natural gas that might be made available for export. Nevertheless, although its revised estimates of gas demand will not be used in the surplus calculation, the Board deems it advisable to publish the results of its current assessment of Canadian energy demand. This appendix is therefore devoted to a discussion of the Board's revised forecast.

The Board used a total energy approach in arriving at its estimates of natural gas demand. The methodology employed was the same as that which had been outlined in the Board's most recent reports on the supply and requirements of Canadian oil and natural gas (i.e., the 1978 Oil Report and the 1979 Gas Report).

This forecast reflects the evidence presented at the Licence Phase. It incorporates new assumptions regarding economic and demographic growth and energy prices. These are discussed in the next sections of this appendix, followed by a review of the Board's forecast of energy demand. The final section of this appendix presents the Board's estimates of gas requirements for both the existing market areas for natural gas, as well as for possible expanded markets.

Demographic and Economic Growth

The Board's revised forecast of the Canadian economy, including the demographic projections, was prepared using the Board's version of the CANDIDE 1.2M econometric model and has been reviewed in the light of the evidence received. The assumptions upon which the forecast is predicated have been re-examined since the Board's 1979 Gas Report was prepared and some key assumptions have been changed. For example, the Canadian economy's recent poor performance and the anticipated slowdown in the United States combine to lower the forecast in the short run. As well, slower population growth due to the downward revision in the immigration estimates, results in the projection of weaker real growth than previously forecast. The Board's main projection of the Canadian economy to the year 2000 is summarized in Tables C-1 and C-2 and is identified as the base case forecast. This projection of the economy was used in developing the Board's medium energy demand forecast.

For the 1980's, the Board's forecast is that real growth in Gross National Expenditure (GNE) will average 3.6 percent per year, with 1981 and 1982 exhibiting growth rates above 4 percent. This rate of growth is sufficiently high that the unemployment rate declines throughout the decade. Growth in the 1990's diminishes somewhat to an annual average of 3.4 percent, but, because lower population growth causes slower labour force growth, the unemployment rate continues to decline.

The annual rate of increase in population is expected to slow gradually throughout the forecast period. From average annual historical growth rates of 1.9 percent in the 1960's and 1.2 percent in the 1970's, rates of 1.0 percent and 0.9 percent are predicted for the 1980's and 1990's respectively. The fertility rate is assumed to continue declining until 1980; thereafter it will remain constant at slightly less than two children per female of child-bearing age. Net immigration is assumed to be 80,000 persons in each year until 2000. This is 20,000 fewer persons than assumed in the Board's previous base case forecast. The resultant population at the end of the forecast period is 29 million persons. The population forecast has been reduced to reflect the recent downward revisions in Statistics Canada's population projections. As before, the Board's forecast falls in the middle range of Statistics Canada's

Table C-1
 COMPONENTS OF REAL GROSS NATIONAL EXPENDITURE
 Range of NEB Forecasts
 Average Annual Growth Rates
 (percent per year)

	Actual			Forecast	
	<u>1960-1969</u>	<u>1970-1978</u>		<u>1979-1989</u>	<u>1990-2000</u>
Gross National Expenditure	5.2	4.3	Base	3.6	3.4
			High	4.2	3.8
Business Investment in Plant and Equipment	4.9	4.9	Base	4.9	4.2
			High	5.7	4.0
Residential Construction	2.7	4.0	Base	0.2	0.8
			High	0.8	0.8
Consumer Expenditure	4.6	5.2	Base	3.3	3.5
			High	4.0	4.0
Government Current Expenditure	5.9	3.9	Base	3.1	3.3
			High	3.8	3.8
Exports	8.8	5.2	Base	4.2	3.5
			High	4.6	3.9
Imports	7.2	5.7	Base	3.9	3.9
			High	4.4	4.1

Table C-2
 PROJECTIONS OF THE CANADIAN ECONOMY
 Range of NEB forecasts
 Average Annual Growth Rates
 (percent per year)

	Actual			Forecast	
	1960-1969	1970-1978		1979-1989	1990-2000
Real GNP	5.2	4.3	Base	3.6	3.4
			High	4.2	3.8
Population	1.9	1.2	Base	1.0	0.9
			High	1.1	1.0
Employment	2.9	2.7	Base	1.9	1.5
			High	2.3	1.8
Households	2.9	2.8	Base	1.9	1.4
			High	2.0	1.4
CPI	2.5	7.1	Base	6.8	6.7
			High	7.1	7.2
Real Personal Disposable Income	4.8	5.9	Base	3.3	3.5
			High	3.8	4.1
RDP Commercial Sector	5.3	4.7	Base	3.5	3.5
			High	4.1	4.0
RDP Industrial Sector	5.8	3.4	Base	3.7	3.2
			High	4.4	3.6
Productivity	2.5	1.4	Base	1.8	2.0
			High	2.0	2.1
Unemployment Rate*(%)	5.1	6.7	Base	7.3	5.3
			High	6.8	4.7
Real Per Capita GNP (\$1971 per Person)**	4094	5367	Base	7073	9283
			High	7518	10185

* Average level over period, rather than growth rate.

** Level at end of period, rather than growth rate.

forecasts. The aggregate participation rate in the labour force increases steadily throughout the period to 2000 to reach the level where two-thirds of those of labour-force age are in the labour force. Most of this increase is due to increased participation by females.

The consumer expenditure, housing investment, and government expenditure components of GNE grow more slowly than the overall growth in GNE over the next decade, while business fixed non-residential investment and exports grow more quickly. In the following decade, growth in consumer expenditure increases and joins business investment and exports as the stronger sectors of the economy; however, growth in housing investment and government expenditure continues to be relatively weaker. The weakness in the housing sector is a result of the low population projection and the current high vacancy rate in housing. The weakness in government expenditure derives from an assumption that the current government restraint programs will remain in place.

The export sector leads the economy especially in the first half of the 1980's as the devalued Canadian dollar provides stimulus to this sector. The price advantage gained in the late 1970's should permit exporters to exploit new markets and strengthen their position in existing markets. Moderating rates of inflation and wage increases in the 1980's should allow exporters to maintain their competitive advantage. Service exports in the late 1980's are aided by the assumed completion of a northern gas pipeline for the transshipment of Alaskan gas.

Business investment in plant and equipment is another leading sector in the economy with non-residential construction in the 1980's averaging 5.5 percent annual growth. Moderating inflation and strong export growth are contributing factors to the strength in investment. Investment as a share of GNE increases steadily throughout the forecast period, although most of the increase takes place in the 1980's.

Residential construction is an extremely weak sector, exhibiting an average annual growth rate of only 0.5 percent in the period to 2000. Housing starts average 207,000 per year, with the result that the stock of housing grows at 1.9 percent per year. This rate of increase in housing exceeds that in population (1.0 percent) and households (1.6 percent) with the result that the vacancy rate increases during the next two decades.

There should be more multiple than single housing starts in the next two decades as Canada becomes more urbanized and as home heating costs rise.

Although the savings rate declines slightly from current levels, it remains high by historical standards, averaging ten percent in the forecast period. At this level, it is a dampening factor on consumer expenditure. The persistence of this high savings rate is attributable to rates of inflation which, though moderating from the experience of the 1970's are high relative to the inflation of the 1960's. The high savings rate is also attributable to the favourable tax treatment of savings in the Canadian economy and the contractual nature of a large portion of savings.

The forecast calls for inflation to abate somewhat in the 1980's, but to persist at a relatively high level throughout the forecast period. The forecast rate of inflation as measured by the Consumer Price Index (CPI) declines throughout the 1980's reaching a low of 5.8 percent in 1989. Thereafter, inflation picks up as continued strong economic growth reduces excess capacity and lowers the unemployment rate.

Productivity gains are expected to return to rates closer to the historical average, somewhat above the poor performance of the 1970's, but below the experience of the 1960's. The forecast for annual average productivity gains is 1.8 percent in the 1980's and 2.0 percent in the 1990's. The improvement is a result of an increase in the average age of the work force and the strong investment scenario depicted, mitigated somewhat by the relatively strong growth of the services sector which traditionally exhibits lower than average productivity gains.

In addition to the base case forecast, to assist the Board in analysing the sensitivity of energy demand to varying economic assumptions, the Board has also prepared a more optimistic forecast of the Canadian economy, herein referred to as the "high case". While the base case forecast is made by assuming most likely estimates of exogenous variables, the high case forecast is based on values for exogenous variables which are possible, although less likely, and which are conducive to stronger economic growth. These two forecasts are compared on Tables C-1 and C-2 and were used in conjunction with different price assumptions (which are discussed in the next section) to develop a high

and low energy demand range. The high case economic projection was used in developing the high energy demand forecast, while the base case economic projection was used in developing both the medium energy demand and low energy demand cases.

The high case forecast is characterized by faster growth of population and real Gross National Product (GNP). However, the increased growth in GNP relative to population is such that per capita real GNP is higher by 9.7 percent by the year 2000. Although the unemployment rate is approximately the same in 2000, this rate falls from current levels more quickly in the high case. The CPI increase is at a faster rate, averaging half a percentage point higher each year of the forecast.

The assumption changes in the high case fall into two broad categories: those that increase the economy's growth potential and those that increase demand.

To increase the economy's potential, the immigration assumption was altered such that the high case has 10,000 more immigrants in 1980, and 20,000 more in subsequent years than the base case forecast which held net immigration constant at 80,000 persons per year. The resultant population of 29.5 million in the year 2000 is one-half million greater than in the base case. Furthermore, the percentage of working age people who are in the labour force was assumed to increase more rapidly than in the base case, resulting in the average labour force participation rate reaching 70 percent by 2000 compared with 66 percent in the base case.* Also, the average annual increase in the productivity of Canadian workers is projected to be 2.1 percent in the high case versus 1.9 percent in the base case.

Domestic demand throughout the forecast is increased by assuming that the savings rate of consumers will be lower in the high case. The savings rate of 10.0 percent in the base case is lowered to 9.3 percent in the high case. A two billion dollar temporary tax cut for 1980 and additional investment throughout the forecast period have been included in the high case.

On the trade scene the high case forecast assumed that the outlook for the United States and overseas economies would be stronger, thus providing stimulus to Canadian exports. Furthermore, it was assumed

* These data are based on the old labour force survey definitions which included 14-year olds as potential labour force entrants.

that the Canadian dollar, rather than appreciate four cents in the next four years as in the base case, would remain constant at 86¢ (U.S.) throughout the period to 2000, resulting in import substitution and additional exports.

Energy Prices and Interfuel Competition

Since the preparation of the 1979 Gas Report, world oil prices have been increased by the OPEC nations much more rapidly than had been expected. In fact, prices were raised more rapidly than had been announced by OPEC earlier this year. Since the international price of crude oil is a major factor in determining domestic crude oil price levels, which, in turn, influence natural gas prices, the Board has incorporated these latest changes in its price projections. Because of the uncertainties regarding future energy prices, the Board forecasts energy demand under different price scenarios.

For its medium demand case, the Board has assumed that the landed cost of imported crude oil at Montreal will average approximately \$142.80/m³ (\$Cdn)⁽¹⁾ in 1979 (about \$22.70/Bbl). For 1980, it is expected to remain at the price assumed for the second half of 1979, i.e. approximately \$161.50/m³ in 1979 dollars (about \$25.70/Bbl), and to remain constant in real terms thereafter. This new constant price is 49 percent higher than that which had been assumed in the 1979 Gas Report, which illustrates the magnitude and impact of the recent OPEC price increases.

Canadian crude oil prices are assumed to reach world levels by the beginning of 1983, one year later than had been assumed in the 1979 Gas Report. This implies an approximate increase of \$31.50/m³ (\$5.00/Bbl) in each year between 1979 and 1983.

For existing markets, natural gas prices are assumed to maintain the current 85 percent price relationship with oil on an energy equivalent basis, at the Toronto city gate. In British Columbia, where the price relationship is currently about 55 percent relative to oil at Vancouver, it is assumed that the 85 percent level will be attained by the end of 1984.

With respect to expanded markets in Quebec and the Maritimes, for purposes of this report, the Board is using the same market expansion

(1) All prices quoted in this section are quoted in Canadian dollars.

volumes as presented in the 1979 Gas Report. Those estimates had been developed on the basis of assuming approximately a 70 percent price relationship of the city-gate price of gas relative to the refinery-gate price of crude. It was assumed that this price relationship would result in burner tip prices which would encourage expansion into new market areas. However, it was also assumed that the price advantage for gas would be gradually decreased towards the end of the forecast period.

Different price assumptions are made for the low and high energy demand cases. In the low demand case it is assumed that the world price of crude oil will increase in real terms by approximately five percent per annum. Correspondingly, in the high demand case it is assumed that the price will decrease in real terms by approximately five percent annually. The resulting range of energy demand is presented and discussed in the next section of this appendix.

In calculating burner tip prices, it is assumed that transportation and distribution margins for petroleum products and natural gas will remain constant in real terms, for all cases. For the base case forecast, which assumes that Canadian crude oil prices increase to 1983 and then remain constant in real terms, this results in burner tip prices that remain constant in real terms after 1983.

For the low and high energy demand cases, which assume a real increase and decrease respectively of five percent per annum in crude oil prices, the assumption of constant transportation and distribution margins results in burner tip prices that increase and decrease respectively in the order of four or five percent per annum.

Electricity prices are assumed to increase until 1982 at those rates for which the various electric utilities have applied, or which have already been approved by the regulatory agencies. After 1982, electricity rates are assumed to remain constant in real terms for Canada overall, although the Board recognizes that there could be regional differences with respect to price movement. The Board also acknowledges that there are different opinions within the industry as to whether the price of electricity will increase or decrease in real terms, or whether it will in fact remain constant. In this regard, the Board has allowed for a variation of plus or minus four percent per annum in the real price of

electricity in developing its low and high energy demand forecasts, respectively.

In general, as a consequence of the Board's price assumptions, electricity prices are forecast to increase at a somewhat slower rate of growth than the price of fossil fuels. This reduces the energy equivalent price differentials, which now favour fossil fuels, and also moderates the increases in weighted average energy prices caused by the escalating prices of imported crude oil.

Based on the above assumptions, burner tip energy prices have been developed for selected fuels in each market sector and region. Table C-3 shows selected fuel prices in Ontario, illustrating the consumer prices projected for the medium case forecast. Table C-4 shows the relative price ratios, after adjustments for efficiency differences, and indicates the direction of the changes in the projected relative prices.

The assumptions just outlined regarding energy prices have been used in conjunction with other factors in developing the market shares that are incorporated into the Board's forecast. These market shares were developed on the basis of considering relative energy prices, relative capital costs of installing heating equipment, historical and current trends, and the evidence presented to the Board.

With regard to the Board's forecast of total Canadian demand for natural gas in existing markets, natural gas is expected to increase its market share in the residential sector. This is partly the result of a continued penetration of the heating market by gas at the expense of oil in regions such as Ontario. It is also partly the result of a westward population shift, where natural gas has a very high share of the energy market. The market share held by electricity is expected to increase significantly, reflecting its decreasing relative price and recent trends. The share held by oil is expected to continue to decline throughout the forecast period.

In the commercial sector, the market share of gas is expected to increase to the year 1985, after which it is projected to decline gradually as a result of market saturation. As in the residential sector, the share held by electricity is expected to increase significantly, while

ASSUMED BURNER TIP ENERGY PRICES - ONTARIO

Medium Demand Case
(1979 dollars)

	Imperial Units			Metric Units			Equivalent	
	1980	1983-2000		1980	1983-2000		1980	1983-2000
Crude Oil at Toronto Refinery Gate	\$/Bbl	17.49	25.67	\$/m ³	110.06	161.54	2.86	4.19
Natural Gas at Toronto City Gate	\$/MMBtu	2.56	3.76	\$/GJ	2.43	3.57	2.43	3.57
<u>Residential Sector</u>								
Natural Gas	\$/Mcf	3.75	4.95	\$/GJ	3.56	4.69	3.56	4.69
Light Fuel Oil	¢/gal	71.8	95.2	¢/L	15.8	21.0	4.09	5.42
Electric Appliances*	mil/kW.h	37.84	40.05	mil/kW.h	37.84	40.05	10.52	11.13
Electric Space Heating**	mil/kW.h	25.33	26.81	mil/kW.h	25.33	26.81	7.04	7.45
<u>Commercial Sector</u>								
Natural Gas	\$/Mcf	3.12	4.32	\$/GJ	2.96	4.10	2.96	4.10
Light Fuel Oil	¢/gal	52.9	76.3	¢/L	11.6	16.8	3.01	4.34
Electricity	mil/kW.h	26.89	28.47	mil/kW.h	26.89	28.47	7.47	7.91
<u>Industrial Sector</u>								
Natural Gas	\$/Mcf	2.72	3.92	\$/GJ	2.58	3.72	2.58	3.72
Heavy Fuel Oil	\$/Bbl	16.47	24.66	\$/m ³	103.64	155.18	2.48	3.72
Electricity	mil/kW.h	20.74	21.97	mil/kW.h	20.74	21.97	5.76	6.11

* First 500 kW.h/month

** Between 1 and 5 thousand kW.h/month

Table C-4
RELATIVE PRICE RATIOS⁽¹⁾
ONTARIO

	<u>1980</u>	<u>1983-2000</u>
<u>Residential</u>		
Light Fuel Oil/Electricity for Space Heating	0.89	1.12
Gas/Light Fuel Oil	0.75	0.75
<u>Commercial</u>		
Gas/Light Fuel Oil	1.03	0.99
Gas/Electricity	0.51	0.66
<u>Industrial</u>		
Gas/Heavy Fuel Oil	1.06	1.02
Heavy Fuel Oil/Electricity	0.50	0.70

(1) These ratios are calculated on a thermal equivalent basis and include adjustments for efficiency differences.

the market share for oil is projected to decline to about half of its current level by the year 2000.

For the industrial sector, natural gas is projected to increase its market share, generally at the expense of heavy fuel oil. The shares held by electricity and wood energy are also expected to increase somewhat.

It should be noted that market share behaviour for all sectors varies considerably between regions, reflecting differences in market conditions, relative prices, and the availability of other fuels. As previously noted, the above reference to market shares was in regard to the Board's base case forecast, excluding market expansion. To the extent that additional natural gas sales would result from market expansion in various regions, the market share for natural gas would increase, with a corresponding decrease for competitive fuels. As a percentage of total primary energy demand, the share held by natural gas is projected to increase from its current level of 17.4 percent to 19.3 percent in 1990, including allowances for expanded markets for natural gas. Without market expansion, the Board's forecast indicates that the share held by gas would decline slightly to about 17.0 percent in 1990. The separate market sectors for natural gas are discussed later in this appendix.

Forecast of Total Energy Demand

The Board's revised forecast of total energy demand represents a reduction from the 1979 Gas Report forecast and reflects, among other factors, the constraining influence of higher energy prices and slower economic and demographic growth. The forecast also incorporates the evidence adduced during the Licence Phase, as well as the changes resulting from more recent energy consumption statistics in all sectors, including the transportation sector.

One change of a conceptual nature has been introduced. The Board's forecast in this report includes the use of pulping liquor by the pulp and paper industry. In previous reports, lack of sufficiently reliable historical data had prevented the Board from including the use of pulping liquor in its forecasts of total energy demand, although such use was implicit in the Board's forecast since pulping liquor filled an energy requirement which might otherwise have been supplied by other energy

forms. The Board's forecast now includes the expected use of both hog fuel and pulping liquor, whereas only data on hog fuel had been included in the Board's forecast for the 1979 Gas Report.

The net result of the above revisions is that the Board's medium case forecast of total primary energy demand has been reduced by approximately 2.7 percent for the year 1990 and 3.4 percent for the year 2000. (If the demand data for pulping liquor are excluded, to compare more exactly with the Board's previous forecast of total energy demand, the overall reduction would be 4.8 percent and 5.4 percent, respectively.) The Board's forecast implies an average annual growth rate of approximately 2.7 percent over the forecast period, compared to 3.0 percent in its previous report. Table C-5

PRIMARY ENERGY DEMAND - CANADA

NEB Forecast

Medium Demand Case

(Petajoules)

	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Oil	4 089.2	4 170.5	4 349.9	4 543.5	4 799.0	5 198.0
Natural Gas ⁽¹⁾	1 732.7	1 815.3	2 063.4	2 204.5	2 493.1	2 868.7
Ethane & LPG's	88.8	116.6	150.2	172.1	176.9	181.3
Coal	907.3	993.9	962.2	1 128.2	1 503.6	1 648.5
Hydro & Nuclear ⁽²⁾	2 842.8	3 018.4	3 953.7	4 396.1	5 224.1	6 616.2
Renewable Energy ⁽³⁾	<u>306.6</u>	<u>320.0</u>	<u>393.4</u>	<u>533.1</u>	<u>687.8</u>	<u>881.8</u>
Total Primary Energy	9 967.4	10 434.7	11 872.8	12 977.5	14 884.5	17 394.5

- (1) These figures represent natural gas demand in existing markets only. If expanded markets are included, then the gas demand figures for 1985 and beyond should read as follows:

	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Total Gas Demand	2 266.5	2 501.5	2 855.6	3 287.2

The demand estimates for competing energy forms will have to be reduced accordingly.

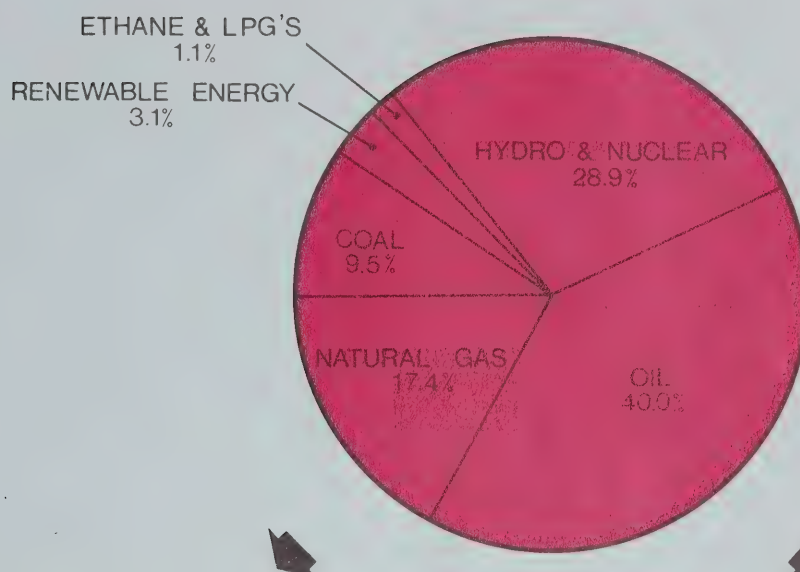
- (2) Expressed on a fuel equivalent basis assuming 10.55 megajoules per kW.h (10,000 Btu's per kW.h).
- (3) Includes solar and wood energy.

PRIMARY ENERGY DEMAND - CANADA

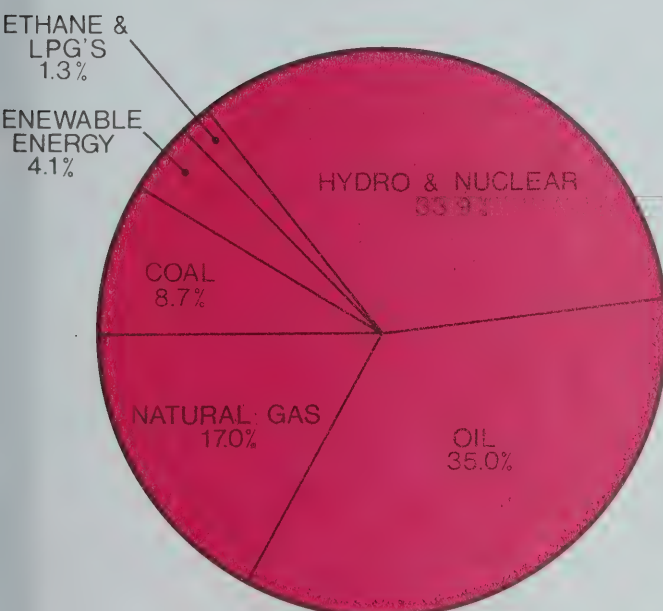
NEB Forecast of Fuel Shares

MEDIUM DEMAND CASE

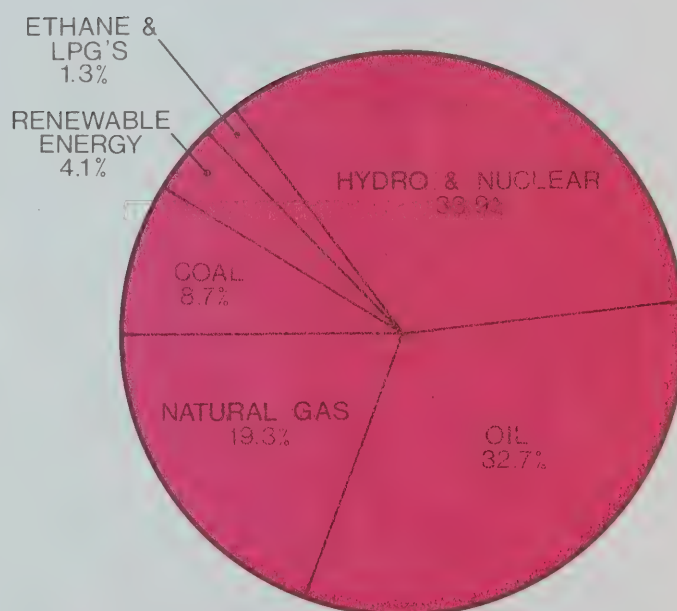
1980



1990

(WITHOUT EXPANDED MARKETS
FOR NATURAL GAS)

1990

(WITH EXPANDED MARKETS)*
FOR NATURAL GAS

* For purposes of this illustration only, the increase in market share for natural gas, which would be expected to result from market expansion, was assumed to be exclusively at the expense of oil products.

Table C-5 presents the Board's estimates of primary energy demand by energy source. For purposes of this table, the natural gas figures that are shown represent the forecast of gas demand in existing markets only. If expanded markets for natural gas were included, then the gas demand figures would be increased accordingly. Correspondingly, there would be a reduction in the demand for competing energy forms, although it is expected that policies and incentives to expand natural gas markets would probably be directed towards displacing oil products. The Board's estimate of total gas demand, including expanded markets, is shown in a footnote to the table.

Figure C-1 illustrates the shares of total primary energy estimated for each energy type for the years 1980 and 1990. For 1990, estimated fuel shares are shown for both the Board's forecast excluding expanded markets for gas as well as for the Board's forecast including expanded markets. For purposes of this illustration, the increase in market share for natural gas, which would be expected to result from market expansion, was assumed to be exclusively at the expense of oil products. However, the Board recognizes that in certain market areas other energy forms might also be displaced to some extent.

As previously explained, in addition to developing a medium demand scenario, the Board also estimated high and low energy demand cases to provide some perspective of the sensitivity of the energy demand forecast to the Board's major underlying assumptions. For example, according to the Board's estimates for the year 1990, the demand for total energy in Canada could be approximately 19 percent higher or 8 percent lower than the medium case demand, depending on the conditions affecting the major determinants of that demand.

The high demand case is based on an optimistic economic forecast, with some decline in real world oil prices. The low demand case is based on the same economic forecast as the medium case, except that world oil prices are assumed to continue to increase in real terms. The Board's projections of total energy demand, under these three scenarios, are compared in Table C-6 and in Figure C-2.

Table C-6
PRIMARY ENERGY DEMAND - CANADA
Range of NEB Scenarios
(Petajoules)

	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
High Demand Case	12 759	15 381	19 552	25 593
Medium Demand Case	11 873	12 978	14 885	17 395
Low Demand Case	11 541	11 981	12 805	13 839

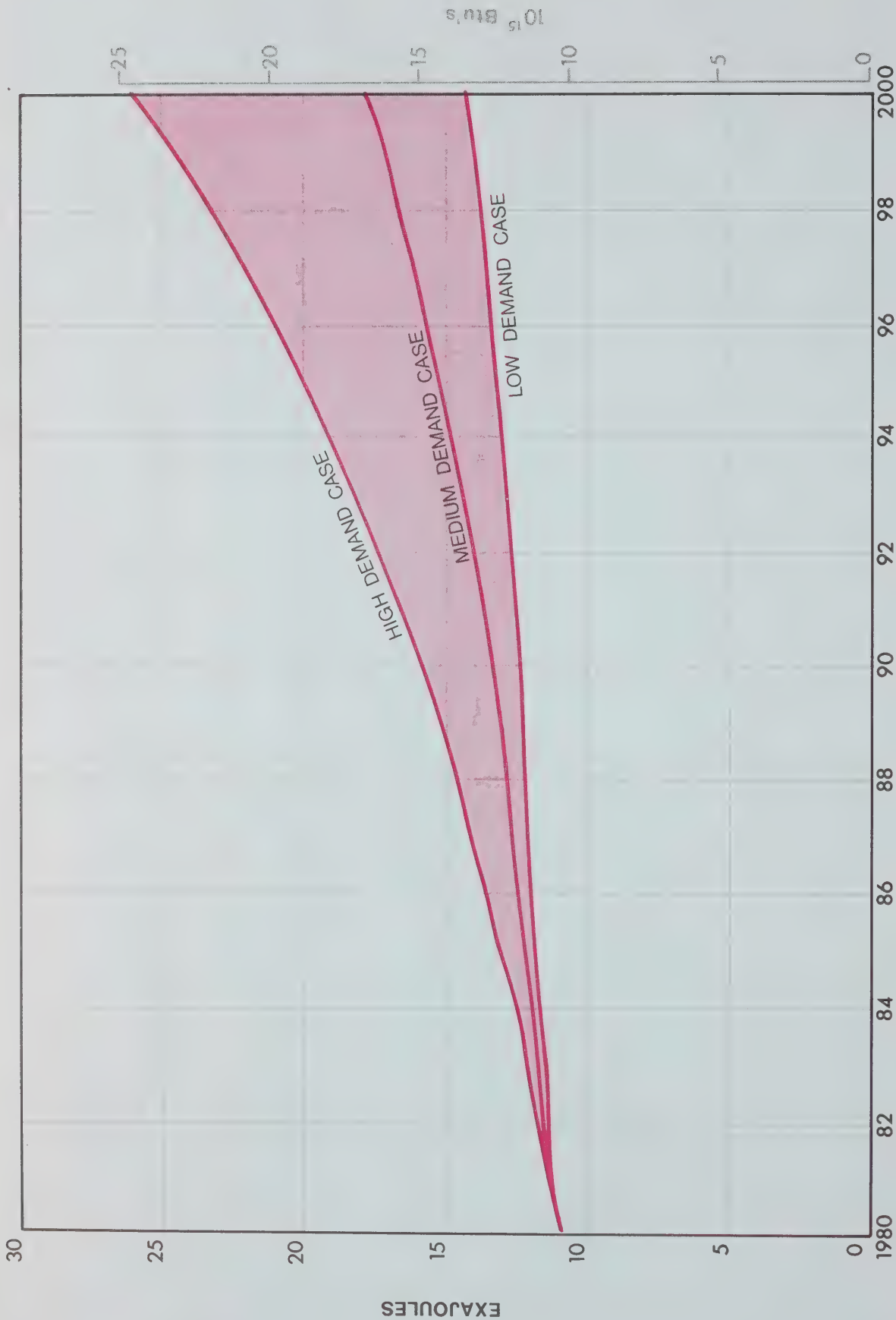
Forecast of Natural Gas Demand

As in the 1979 Gas Report, the Board prepared a gas demand forecast based on the existing markets for natural gas. This base case forecast assumed no expansion of market areas for natural gas in Canada. Subsequently, in addition to the base case volumes, allowance was made for further net sales that would be expected to result from expanded markets, either from extension of gas service to new market areas or from the introduction of specific incentives to further increase natural gas sales in existing market areas.

For Quebec and the Maritimes, the Board used the same volumes as projected in the 1979 Gas Report. While that report only provided for expanded markets in eastern Canada, the Board's new forecast also made provision for market expansion in Ontario and Manitoba, as well as for extension of gas service to Vancouver Island. Existing and expanded markets are discussed separately in the following sections of this appendix.

Existing Markets

Overview In its medium demand case for existing markets, the Board estimates that total net sales of natural gas will increase at an average annual rate of approximately 2.5 percent over the forecast period, as compared to about 3.0 percent in the previous report. This decrease reflects the Board's new assumptions regarding slower economic and demographic growth and higher real energy prices. The demand for natural



PRIMARY ENERGY DEMAND - CANADA
Range of NEB Scenarios

gas is expected to display a lower level of growth in the first years of the forecast period, as compared to the latter years. This results partly from the Board's assumptions that higher real energy prices and other conservation measures are assumed to have had most of their impact by about 1990.

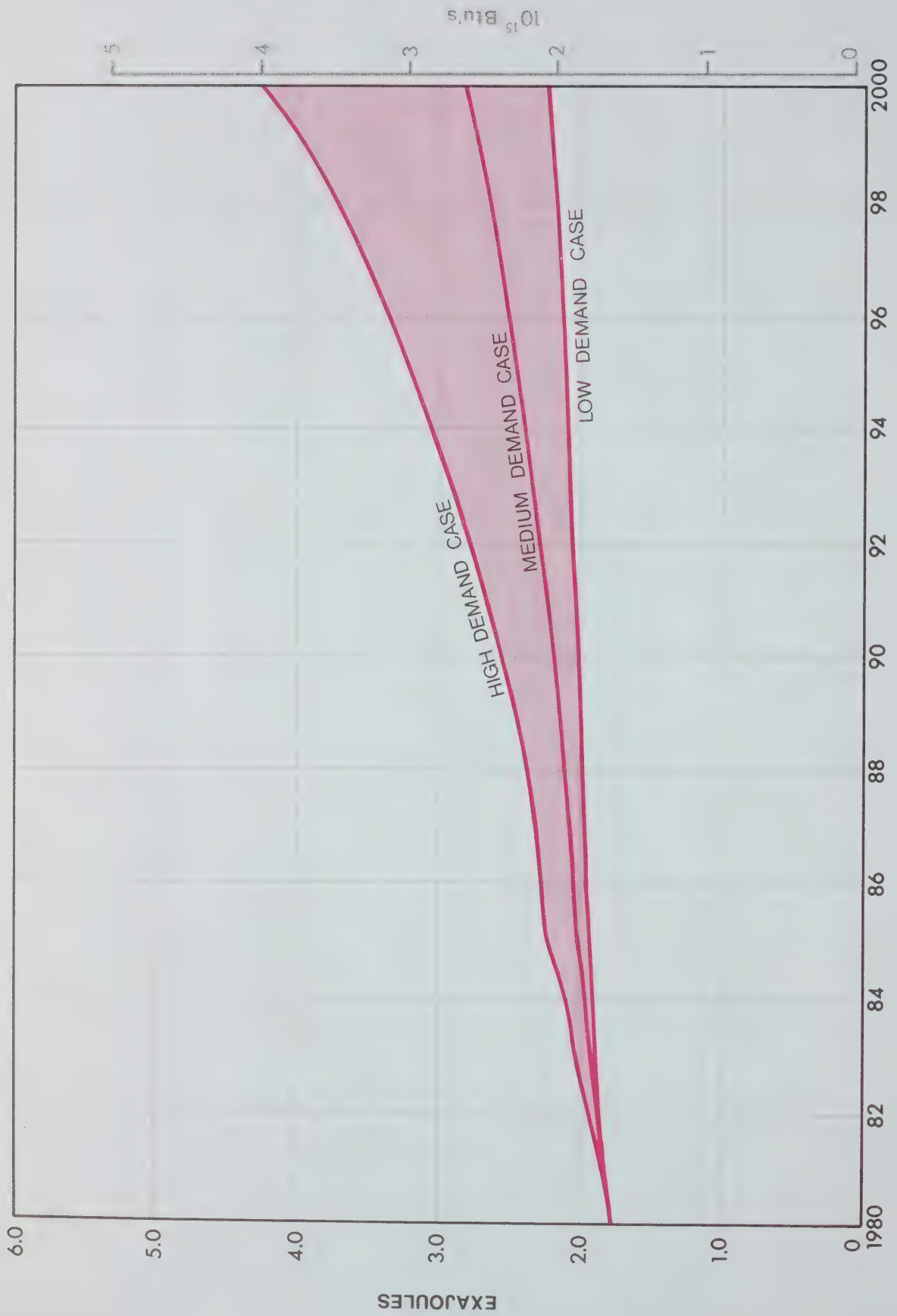
In addition to developing a medium demand case for natural gas, the Board also estimated high and low demand cases. These were based on the assumptions discussed earlier. The results are summarized in Table C-7 and illustrated in Figure C-3. According to the Board's estimates, total net sales of natural gas, based on existing markets, could be approximately 18 percent higher, or 8 percent lower, than the medium demand case for the year 1990.

Table C-7
NET SALES OF NATURAL GAS - CANADA (EXISTING MARKETS)
Range of NEB Scenarios
(Petajoules)

	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
High Demand Case	2 149	2 512	3 149	4 172
Medium Demand Case	1 967	2 121	2 401	2 752
Low Demand Case	1 880	1 944	2 047	2 162

In the Board's medium demand case, total net sales for existing markets are projected to increase from approximately 1.65 EJ in 1979 to 2.12 EJ in 1990, and to 2.75 EJ in the year 2000 (1.56 quads, 2.01 quads and 2.61 quads, respectively). The Board's estimated net sales by province and by market sector are presented, beginning with Table C-9, following the discussion of demand by end-use sector.

Residential Sector The demand for natural gas in the residential sector in existing Canadian markets is forecast to increase from 351 PJ (332 trillion Btu's) in 1979 to 531 PJ (503 trillion Btu's) in 2000. This implies an average annual growth rate of 2.0 percent over the



NET SALES OF NATURAL GAS - CANADA (EXISTING MARKETS)
Range of NEB Scenarios

forecast period. This lower growth rate is consistent with the observed slowing in the growth of natural gas demand from 8.5 percent per annum in the sixties to 3.2 percent over the period 1970 to 1978.

The further decline in the growth of residential gas demand reflects the Board's new assumptions regarding the economy and energy prices, and also reflects a slowing in the rate of penetration of residential markets. The share of residential energy demand held by natural gas is expected to increase from 28.8 percent in 1979 to 32.1 percent in 2000, mainly as a result of further penetration of the Ontario market, and a continuation of the westward shift in population to regions where natural gas is used more extensively.

On a regional basis, the growth in natural gas demand does not vary significantly from that of Canada overall. Growth is greatest in Ontario, averaging 2.3 percent per annum over the entire forecast period, with slightly faster growth to 1985. This is consistent with evidence presented at the hearing which indicated increased interest by oil customers in switching to the use of natural gas. The slowest growth in the residential demand for natural gas occurs in Manitoba and Saskatchewan. It is expected that saturation of existing gas markets in these provinces, combined with a slow total energy growth of approximately 1.5 percent per annum, will lead to an average annual growth in gas demand of 0.8 percent.

The current forecast of demand for natural gas in existing residential markets is 7.9 percent lower in 1990 than was forecast in the 1979 Gas Report. The residential demand for natural gas is affected to a lesser extent, compared to other fuels, by the long-run decreases in demographic and economic growth. This occurs as a result of the assumed stronger westward shift in population, as mentioned previously. However, taking into account the impact of changes in both energy prices and economic growth, the relative decrease in natural gas demand is about the same as for total energy demand in the residential sector.

Commercial Sector The demand for natural gas in the commercial sector is forecast to increase from 381 PJ (361 trillion Btu's) in 1979 to 683 PJ (648 trillion Btu's) in 2000. This implies an average annual growth rate of 2.8 percent.

The current forecast is based upon new projections of real commercial product and energy prices, and also incorporates revisions to the previous forecast to track 1977 actual consumption data. The net effect of these changes is to reduce energy demand in the commercial sector below levels estimated for the 1979 Gas Report. However, the projected market share of natural gas in the commercial sector is higher than the previous estimate. As a result, the percentage reduction in natural gas demand in the commercial sector is smaller than that for commercial total energy demand.

Natural gas demand in the current forecast is estimated to be slightly higher than the previous estimate to 1980 and for the period after 1995. For the period 1980 to 1995 the current forecast of gas demand is lower than the previous estimate by 1.8 percent to 4.5 percent, depending upon the year of comparison. Higher energy prices reinforce the negative impact of lower economic growth on commercial energy demand, especially for the years 1980 to 1995.

On a regional basis, compared to the 1979 Gas Report forecast, the current forecast estimates that Alberta and British Columbia will increase their share of total commercial energy demand in Canada. Conversely, Ontario and Quebec are expected to show a decrease relative to the previous forecast. The shift in population westward partly accounts for the higher market share of gas estimated for the current forecast.

A revision of the previous forecast to track actual volumes of gas used in the commercial sector in 1977 resulted in increasing somewhat the market share of gas over the forecast period. The perception of security of gas supply is also expected to maintain an upward trend in demand for natural gas. Thus, the market share of gas is estimated to increase from 41.8 percent in 1979 to 43.3 percent in 1985, after which it is projected to decline gradually to 37.6 percent in 2000 as a result of market saturation. The previous forecast estimated the market share of gas at 40.9 percent in 1985 and at 36.5 percent in 2000.

The current forecast estimates an increase in gas demand in the commercial sector at an average annual rate of 2.6 percent during the period 1979 to 1990, and at 3.1 percent during the period 1990 to 2000. The corresponding rates in the previous forecast were 3.3 percent and 2.2 percent, respectively.

Industrial Sector - The demand for natural gas in the industrial sector is forecast to increase from 619 PJ (587 trillion Btu's) in 1979 to 1090 PJ (1034 trillion Btu's) in 2000. This implies an average annual growth rate of 2.7 percent.

The industrial demand for natural gas in the present forecast is expected to grow less rapidly than had been anticipated at the time of the 1979 Gas Report, when a 4.0 percent growth rate was projected. As a result, the Board's new forecast of gas demand is 6.8 percent lower for the year 1990. In addition to the effect of higher energy prices, the reduction in the Board's forecast results to a great degree from the assumption that the rate of growth in industrial economic activity will be much lower than previously expected. The Board's forecast does include, however, additional volumes of natural gas for oil sands operations in Alberta, over and above those volumes that it had previously forecast, for the period between 1985 and 1990. This reflects the latest forecast of AERCB⁽¹⁾, wherein it had assumed that the Great Canadian Oil Sands and Syncrude plants would use gas both as fuel and as feedstock until year-end 1990. Thereafter, it considered that these two plants, plus additional plants expected to come on-stream, would require gas only as a feedstock.

A comparison of the growth rates for natural gas with that of oil, electricity and total energy, shows gas demand experiencing the highest growth rate. The market share of total energy demand held by gas is expected to increase from 31.6 percent in 1980 to 35.5 percent in the year 2000. This increased share is generally at the expense of heavy fuel oil.

There are noticeable differences both over time and between regions in industrial gas demand growth during the forecast period. From 1980 to 1990, the demand for gas grows at an average annual growth rate of 2.1 percent and, from 1990 to 2000, it is expected to grow at 3.2 percent. On a regional basis the forecast indicates higher growth rates of natural gas demand in the western provinces, due to the relatively lower price of gas and higher predicted economic activity in the industrial sector.

Inclusion of the use of pulping liquor in the Board's energy supply and demand statistics has increased the level of total energy

(1) AERCB Report 78-I

demand in the industrial sector. The Board expects that the use of pulping liquor and hog fuel by the pulp and paper industry will continue to increase throughout the forecast period. Part of this increase results in the displacement of further volumes of heavy fuel oil and natural gas. The overall impact on gas demand is, however, minimal. The Board's estimated use of hog fuel and pulping liquor is presented in Table C-8, which also illustrates the Board's estimates of the quantities of fossil fuel displaced.

Table C-8
PROJECTED USE OF HOG FUEL AND PULPING LIQUOR,
AND DISPLACEMENT OF FOSSIL FUELS
NEB Forecast - Total Canada
(Petajoules)

Year	Estimated Use			Estimated Displacement of Fossil Fuels		
	Hog Fuel	Pulping Liquor	Total	Natural Gas	HFO	Total
1980	102.64	217.28	319.15	11.61	17.94	29.55
1985	132.68	247.40	380.08	19.08	27.00	46.08
1990	168.01	279.92	447.93	27.69	36.11	63.80
1995	189.25	316.70	505.95	30.85	41.93	72.51
2000	211.32	358.32	569.64	33.48	44.03	77.51

Thermal Electric Sector - The Board's forecast in this sector includes gas requirements for electricity generation by the major electrical utilities of Canada and also by the minor utilities and by industry. It was developed by subdividing the provincial demands for electricity into the demands to be met by each of these subsectors and then determining the corresponding quantities of each energy type required to meet the forecast demand. The latter quantities were based on an analysis of evidence submitted to the Board, including that submitted during the 1978 Gas Inquiry, on the most recently known utility expansion plans, and on appropriate historical data.

The natural gas demand for thermal generation in Canada is forecast to grow from 120 PJ (114 trillion Btu's) in 1979 to 179 PJ (170 trillion Btu's) in the year 2000. These gas requirements imply an average annual growth rate of 1.9 percent over the forecast period. In general, this growth rate results from the expectation that electricity will not grow as rapidly in the forecast period as it has in the past, and also that other energy types will be increasingly substituted for gas in the generation of electricity. The demand for natural gas for the generation of electricity by industry is expected to continue to grow. The corresponding demand by major provincial utilities is expected to remain essentially constant, except for a decrease in Ontario, with the mothballing of five units of the Hearn Station, and an increase in Alberta, with the construction of a gas turbine station at Medicine Hat.

Petrochemical Sector - The Board has reviewed the petrochemical sector and, based on currently available information, there appears to be no reason to change the forecast of natural gas requirements for petrochemical feedstock, as presented in the 1979 Gas Report.

Table C-9

NET SALES OF NATURAL GAS - CANADA (EXISTING MARKETS)

NEB Forecast

(Petajoules)

	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Residential	350.5	362.0	390.1	427.0	478.8	530.7
Commercial	380.7	393.6	457.6	502.8	578.6	682.8
Petrochemical	177.5	185.9	229.0	250.1	267.3	269.4
Other Industrial	619.3	656.0	732.2	801.6	915.6	1 090.0
Thermal Electric*	<u>120.0</u>	<u>128.9</u>	<u>158.0</u>	<u>139.1</u>	<u>160.3</u>	<u>179.1</u>
Total Net Sales	1 648.0	1 726.4	1 966.9	2 120.2	2 400.6	2 752.0

* Includes thermal generation of electricity by industry as well as by utilities.

Table C-10
 NET SALES OF NATURAL GAS - QUEBEC (EXISTING MARKETS)
 NEB Forecast
 (Petajoules)

	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Residential	19.0	20.7	23.0	24.9	27.6	30.2
Commercial	16.3	17.5	18.2	21.8	28.8	39.0
Petrochemical	--	--	--	--	--	--
Other Industrial	61.6	64.2	71.0	76.2	85.8	101.7
Thermal Electric*	<u>0.1</u>	<u>0.1</u>	<u>0.1</u>	<u>0.1</u>	<u>0.1</u>	<u>0.1</u>
Total Net Sales	97.0	102.5	112.3	123.0	142.3	171.0

* Includes thermal generation of electricity by industry as well as by utilities.

Table C-11
 NET SALES OF NATURAL GAS - ONTARIO (EXISTING MARKETS)
 NEB Forecast
 (Petajoules)

	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Residential	146.1	153.8	171.3	189.3	213.3	237.4
Commercial	169.5	174.4	212.5	232.4	267.7	314.3
Petrochemical	33.7	33.7	33.7	34.8	34.8	34.8
Other Industrial	323.6	346.7	370.5	391.0	438.0	505.5
Thermal Electric*	<u>42.7</u>	<u>35.3</u>	<u>36.2</u>	<u>39.7</u>	<u>42.8</u>	<u>46.2</u>
Total Net Sales	715.6	743.9	824.2	887.2	996.6	1 138.2

* Includes thermal generation of electricity by industry as well as by utilities.

Table C-12

NET SALES OF NATURAL GAS - MANITOBA (EXISTING MARKETS)

NEB Forecast

(Petajoules)

	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Residential	23.8	23.7	23.1	24.4	26.4	28.1
Commercial	22.4	23.4	25.5	28.2	33.2	40.6
Petrochemical	3.7	3.7	3.7	3.7	3.7	3.7
Other Industrial	19.4	19.7	21.3	22.9	26.6	31.7
Thermal Electric*	<u>--</u>	<u>--</u>	<u>--</u>	<u>--</u>	<u>--</u>	<u>--</u>
Total Net Sales	69.3	70.5	73.6	79.2	89.9	104.1

* Includes thermal generation of electricity by industry as well as by utilities.

Table C-13

NET SALES OF NATURAL GAS - SASKATCHEWAN (EXISTING MARKETS)

NEB Forecast

(Petajoules)

	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Residential	30.1	30.1	29.6	31.0	33.3	35.3
Commercial	12.1	12.4	13.3	13.4	14.1	15.2
Petrochemical	--	--	--	--	--	--
Other Industrial	53.5	55.0	58.6	66.4	82.5	107.3
Thermal Electric*	<u>15.2</u>	<u>15.8</u>	<u>11.1</u>	<u>6.4</u>	<u>6.8</u>	<u>7.3</u>
Total Net Sales	110.9	113.3	112.6	117.2	136.7	165.1

* Includes thermal generation of electricity by industry as well as by utilities.

Table C-14
NET SALES OF NATURAL GAS - ALBERTA (EXISTING MARKETS)
NEB Forecast
(Petajoules)

	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Residential	90.3	92.1	96.9	107.3	122.6	138.6
Commercial	121.3	124.7	132.7	140.6	154.4	174.5
Petrochemical	135.3	143.7	186.9	206.9	224.1	226.2
Other Industrial	104.8	114.8	136.3	152.4	158.3	184.3
Thermal Electric*	<u>52.3</u>	<u>65.2</u>	<u>93.6</u>	<u>63.4</u>	<u>70.5</u>	<u>79.3</u>
Total Net Sales	504.0	540.5	646.4	670.6	729.9	802.9

* Includes thermal generation of electricity by industry as well as by utilities.

Table C-15
NET SALES OF NATURAL GAS - BRITISH COLUMBIA (EXISTING MARKETS)
NEB Forecast
(Petajoules)

	<u>1979</u>	<u>1980</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Residential	41.2	41.6	46.2	50.0	55.6	61.1
Commercial	39.1	41.2	55.4	66.4	80.5	99.3
Petrochemical	4.7	4.7	4.7	4.7	4.7	4.7
Other Industrial	56.3	55.6	74.5	92.8	123.8	159.6
Thermal Electric*	<u>9.7</u>	<u>12.5</u>	<u>17.0</u>	<u>29.5</u>	<u>40.1</u>	<u>46.2</u>
Total Net Sales	151.0	155.6	197.8	243.4	304.7	370.9

* Includes thermal generation of electricity by industry as well as by utilities.

Expanded Markets

During the 1978 Gas Inquiry, the Board conducted a detailed analysis of the extent to which natural gas could penetrate energy markets beyond existing gas transmission systems. A considerable amount of information was provided at the Inquiry to assist the Board in its assessment of these new markets. The Board subsequently published its estimates of market expansion volumes in the 1979 Gas Report.

These volumes represented the potential for sales that might be expected to result from expansion of natural gas service into new market areas of Quebec and into the Maritime provinces. The estimates were predicated upon specific assumptions as to the relative prices of natural gas and competing fuels and the disposition of surplus fuel oil existing in those market areas. These assumptions were described in the Board's report. It cautioned, however, that the Board had not studied the conditions under which these assumptions might materialize, nor did it intend to imply that they would in fact materialize. Nevertheless, the Board deemed that it would be prudent to set volumes of natural gas aside for these expansion markets until it could be demonstrated in a subsequent hearing that such markets did exist and that such expansion was feasible.

In this regard, the Certificate Phase of this Hearing was scheduled to consider the applications of Q & M and TCPL for expansion of facilities in Quebec and into the Maritimes. Pending the disposition of these applications, the Board cannot reach final conclusions on the economic feasibility of the proposed expansion or on the market potential indicated by these proposals. However, in the light of the evidence presented during the Licence Phase of the Hearing, the Board is reassured that its base case estimates of additional gas sales in eastern Canada, as presented in the 1979 Gas Report, appear to adequately represent the potential in new market areas of Quebec and the Maritimes, pending the outcome of the Certificate Phase of the Hearing.

With regard to Manitoba and Ontario, the Board has also allowed in its new forecast for additional sales in these provinces as a result of possible incentive pricing in the residential and commercial market sectors. These estimates were largely based on those of TCPL. Inasmuch as the Board also sees a potential for additional sales in the industrial sector, the Board deems that it would be advisable to increase the

allowance for Manitoba and Ontario market expansion by an amount equal to that of the residential and commercial sectors. The Board has assumed these sales to begin in 1981.

With regard to the possible extension of gas service to Vancouver Island, the Board has adopted the estimates submitted by Westcoast, whose estimates were also considered adequate by British Columbia. In the light of the uncertainties of market potential, relative pricing of fuels, etc., the Board chose to adopt Westcoast's estimates, as opposed to the lower estimates of B.C. Hydro. The Board assumed the start-up year to be 1983.

The market expansion volumes discussed above are summarized in Table C-16. These volumes, when consolidated with the medium demand case volumes for existing markets, result in the Board's estimates of total natural gas net sales, including the potential of expanded markets, as shown in Table C-17. These estimates imply an average annual growth rate of approximately 3.1 percent over the forecast period.

Table C-16

NET SALES OF NATURAL GAS - EXPANDED MARKETS

NEB Forecast

(Petajoules)

<u>Expanded Market</u>	Start-up*				
	<u>Year</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
Quebec	15	82	139	175	200
Atlantic	<u>17</u>	<u>44</u>	<u>53</u>	<u>61</u>	<u>69</u>
Sub Total	32	126	192	236	269
Manitoba and Ontario	6	40	53	61	71
Vancouver Island	<u>15</u>	<u>19</u>	<u>26</u>	<u>34</u>	<u>43</u>
Total	53	185	271	331	383

* Start-up year: Quebec - 1981
 Atlantic - 1982
 Manitoba and Ontario - 1981
 Vancouver Island - 1983

Table C-17

TOTAL NET SALES OF NATURAL GAS - CANADA
INCLUDING EXPANDED MARKETS
NEB Forecast⁽¹⁾

NEB FORECAST	1979		1980		1985		1990		1995		2000	
	PJ	10^9 m^3	PJ	10^9 m^3	PJ	10^9 m^3	PJ	10^9 m^3	PJ	10^9 m^3	PJ	10^9 m^3
Base Case (Medium Demand)	1 648	44.3	1 726	46.4	1 967	52.8	2 121	57.0	2 401	64.5	2 752	73.9
Quebec Market Expansion	-	-	-	-	82	2.2	139	3.7	175	4.7	200	5.4
Atlantic Market Expansion	-	-	-	-	44	1.2	53	1.4	61	1.6	69	1.9
Ontario/Manitoba Market Expansion	-	-	-	-	40	1.1	53	1.4	61	1.6	71	1.9
Vancouver Island Market Expansion	-	-	-	-	19	0.5	26	0.7	34	0.9	43	1.2
Total Net Sales ⁽²⁾	1 648	44.3	1 726	46.4	2 152	57.8	2 392	64.3	2 732	73.4	3 135	84.2

(1) NEB Forecast converted to cubic metres assumes 37.22892×10^6 joules per cubic metre.

(2) Totals for cubic metres might not add due to rounding.

APPENDIX D

TRANSCANADA PIPELINE SYSTEM CAPABILITY

EXISTING AND FORECAST

Introduction

The principal system transporting natural gas to markets east of Alberta consists of three major sections: the Western Section of TransCanada from Empress to Winnipeg, the Central Section of TransCanada from Winnipeg to Toronto through Ontario, and the TransCanada/Great Lakes System from Winnipeg to Sarnia through the United States. Currently about 65 percent of Eastern Canadian requirements are met by deliveries through the Central Section; the remaining 35 percent is met by deliveries through the Great Lakes Section.

With respect to the Western Section, the heaviest throughput demands are encountered in the winter months. Therefore the requirements on the capacity of the Western Section for the winter months constitute the "base" against which additional deliveries on the Section must be assessed. On the other hand, because of the large storage facilities in Ontario and because of ACQ contracts, the deliveries on the Central Section are greater during the summer period than during the winter period.

TransCanada submitted evidence showing the throughput requirements in its system for several scenarios⁽¹⁾. Based on that evidence, the Board prepared a forecast of throughput requirements for the years 1979-80 to 1983-84 inclusive, shown at Table D-1.

The Board's estimates are based on evidence provided by TransCanada, reflecting its current requirements, and on the Board's forecast of growth in demand in market areas served by TransCanada. The Board has made the following assumptions in preparing these estimates;

1. TCPL's estimated 1979-80 requirements, excluding interruptible exports, are firm;
2. that Canadian expansion markets utilize natural gas at rates as set out in Appendix 4-A of the Board's 1979 Gas Report (and as shown in Table G-2 of Appendix G);
3. that growth in existing Canadian markets will be 2.9 percent per year (as given in Table 3-7, page 49 of the Board's 1979 Gas Report); and
4. that, as a base case, no additional exports are approved.

(1) Submitted as Exhibit 12-34

Table D-1
TRANSCANADA PIPELINES LIMITED
FORECAST THROUGHPUT REQUIREMENTS
(10^9 m^3)

<u>Contract Year</u>	<u>TCPL Canadian Deliveries</u>	<u>Exports and Transportation</u>	<u>Eastern Expansion</u>	<u>Total Requirements</u>
1979-80	23.56 ⁽¹⁾	6.69 ⁽³⁾	-	30.25
1980-81	24.24 ⁽²⁾	6.59	0.45 ⁽⁴⁾	31.28
1981-82	24.95	6.57	1.42	32.94
1982-83	25.67	6.57	2.15	34.39
1983-84	26.41	6.57	2.92	35.90

Notes: Existing Capacity of the Western Section is $35.09 \times 10^9 \text{ m}^3/\text{year}$.

	<u>Bcf</u>	<u>10^9 m^3</u>
(1) TransCanada 1979-80 Basic Deliveries (Column 1, Table 1 from Exhibit 12-34)	1 120	31.73
plus GL-1 extension 1979-80 (Column 4, Table 1 from Exhibit 12-34)	<u>22</u>	<u>0.62</u>
	1 142	32.35
less TransCanada Exports (Table D-2)	<u>(291.9)</u>	<u>(8.27)</u>
	850.1	24.08
less TransCanada Transportation obligation	<u>(18.2)</u>	<u>(0.52)</u>
Total TransCanada Canadian Deliveries	831.9	23.56
(2) TransCanada 1980-81 Canadian Deliveries (23.56×1.029) = $24.24 \times 10^9 \text{ m}^3$		
(3) Exports in 1979-80 ($8.27 \times 10^9 \text{ m}^3$) less Licence GL-1 ($2.10 \times 10^9 \text{ m}^3$) plus transportation ($0.52 \times 10^9 \text{ m}^3$) = $6.69 \times 10^9 \text{ m}^3$.		
(4) Column 8 of Table G-2 of Appendix G.		

Table D-2
TRANSCANADA'S 1979/80
EXPORT OBLIGATIONS

VIA EMERSON

<u>EXPORT LICENCE</u>	<u>ANNUAL VOLUME</u> (10^9 m^3)	<u>TOTAL</u> (10^9 m^3)
GL-1	2.10	
GL-18	1.48	
GL-39	0.07	
GL-20	0.91	
GL-37	2.03	
GL-43	0.48	
GL-38	0.52	
		7.59

VIA CENTRAL SECTION

<u>EXPORT LICENCE</u>	<u>ANNUAL VOLUME</u> (10^9 m^3)	
GL-28 & 29 **	0.34	
GL-6*	0.16	
GL-19	0.18	0.68
TOTAL EXPORT		<u>8.27</u>

* Licence held by Niagara

** Reduces to 22.0 by 1981

While the Board used TransCanada's evidence to calculate throughput requirements for 1979-80, as described in the table, it forecast the total requirements in subsequent years based on a 2.9 percent growth in TCPL's Canadian Deliveries, the percentage growth in sales in existing Canadian gas markets forecast by the Board for the period 1978-90 in the 1979 Gas Report. The Board also assumed existing exports and Eastern Canada market expansion as set out in the 1979 Gas Report ⁽¹⁾. For example, the total requirements for 1980-81 were calculated as follows:

	(10 ⁹ m ³)
(i) TCPL Canadian Deliveries (Table D-1)	
(1979-80) 23.56 x 10 ⁹ m ³ x 1.029	24.24
(ii) Exports and Transportation	6.59
(iii) Eastern Expansion	<u>0.45</u>
Total Requirements	31.28

With the total system throughput requirements established in this manner, the Board was then able to estimate the throughput capacity and requirements on TransCanada's Western and Central Sections.

Western Section Surplus Capacity

TransCanada submitted evidence based on the assumption that Licence GL-1 would be extended. Therefore, the total requirements shown in Table D-1 would need to be increased by $2.10 \times 10^9 \text{ m}^3$ (74 Bcf) if they were to be comparable with the TCPL evidence. The total requirements for 1980-81 of $31.28 \times 10^9 \text{ m}^3$ would similarly be increased to $33.38 \times 10^9 \text{ m}^3$.

For the Western Section, the winter season and summer season net throughput requirements were calculated based on the ratio of the Board's forecast of annual requirements (i.e., $33.38 \times 10^9 \text{ m}^3$) to TransCanada's estimate of annual requirements ⁽²⁾ (i.e. $33.77 \times 10^9 \text{ m}^3$). The winter and summer requirements were calculated to be $14.83 \times 10^9 \text{ m}^3$ and $18.55 \times 10^9 \text{ m}^3$ respectively.

(1) Appendix 4-A, page 1 of 11, columns (8) and (9).

(2) As given in Exhibit 12-22, Schedule 1, Table A-2.

The average winter day requirement was calculated to be $98.2 \times 10^6 \text{ m}^3$, based on a 151-day winter season. Assuming a 95 percent availability, the available throughput capability would equal $102.98 \times 10^6 \text{ m}^3$ per day. The Western Section surplus capacity would therefore be $4.78 \times 10^6 \text{ m}^3$ per day. During the summer season, the surplus capacity would be greater, but the $4.78 \times 10^6 \text{ m}^3$ per day ($1.74 \times 10^9 \text{ m}^3$ per year) represents the amount which might be considered available on a firm basis. If Licence GL-1 were not extended, the surplus capacity would be increased by $2.1 \times 10^9 \text{ m}^3$ per year. to $3.84 \times 10^9 \text{ m}^3$ per year.

Central Section Surplus Capacity

TransCanada submitted evidence⁽¹⁾ showing the Central Section capabilities versus throughput requirements in the operating year 1980-81.

TransCanada estimated the winter season and summer season throughput requirements to be $5.76 \times 10^9 \text{ m}^3$ and $8.21 \times 10^9 \text{ m}^3$ respectively. Assuming the same relationship between the Board's estimate and TransCanada's estimate as described in the Western Section, the winter season and summer season throughput requirements were calculated for the Central Section to be $5.59 \times 10^9 \text{ m}^3$ and $7.99 \times 10^9 \text{ m}^3$ respectively. The calculated average daily winter and summer rates were $37.0 \times 10^6 \text{ m}^3$ and $37.3 \times 10^6 \text{ m}^3$. Since the summer season average daily rate is greater than the winter season average daily rate, it will limit the surplus capacity on a firm basis.

TransCanada's evidence showed a net throughput capability of $44.0 \times 10^6 \text{ m}^3$ per day for the summer season in the operating year 1980-81. Assuming a 95 percent availability, the available throughput capability would be $41.8 \times 10^6 \text{ m}^3$ per day, yielding a surplus of $4.5 \times 10^6 \text{ m}^3$ per day, or ($1.64 \times 10^9 \text{ m}^3$ per year).

If TransCanada's Canadian requirements, exclusive of Eastern expansion volumes, increased by 2.9 percent, the summer season average day requirement would increase from $37.3 \times 10^6 \text{ m}^3$ for 1980-81 to $38.3 \times 10^6 \text{ m}^3$ for 1981-82.

The surplus capacity for 1981-82 would therefore be $3.5 \times 10^6 \text{ m}^3$ per day ($1.28 \times 10^9 \text{ m}^3$ per year). This surplus capacity would be further reduced to $0.31 \times 10^9 \text{ m}^3$ per year by the estimated increase in gas demand for Eastern expansion markets.

(1) Table B-2, Schedule 1, Exhibit 12-22

Potential Surplus Capacity in the TransCanada System

Using the requirements forecast set out in the 1979 Gas Report, the Board has forecast throughputs on the TransCanada system to determine potential future surplus capacity in the TransCanada system (with results shown on Table 7.2.9.1 and 7.2.9.2 in Chapter 7). The following assumptions were made:

1. the new exports of Consolidated will not be diverted to the prebuilt facilities of Foothills, but rather are carried by TransCanada throughout the term of the licence;
2. existing export licences for gas carried by TransCanada but not subject to the current proceedings expire as they reach their term, without extension;
3. Canadian requirements for gas in markets served by TransCanada are those set out in Table G-2 of Appendix G;
4. the existing capacity in the Great Lakes system is fully utilized before the volumes in the TransCanada Central Section are increased, and no expansion of the Great Lakes system occurs; and
5. new TransCanada facilities will be constructed as required to carry the projected volumes in each year (i.e., the capacity in any year is the greater of that year's throughput requirements or the largest previous annual throughput requirement).

The Board's forecast was derived from the following tables:

Table D-3 reflects total Canadian requirements East of Alberta and current export authorizations.

Table D-4 shows the new exports which would be transported through the TransCanada system.

Table D-5 shows the base case throughput requirements for the Western Section of the TransCanada system.

Table D-6 shows the base case throughput requirements for the Great Lakes and Central Sections.

Tables D-7 and D-8 show the export case throughput requirements for the three sections of the TransCanada system.

If the assumption is made that there will be facilities constructed to handle the throughput requirements as estimated in Tables D-5 through D-8, some capacity will be idled in the TransCanada System in future years. However, as summarized in Tables 7.2.8.1 and 7.2.8.2, and in Figures 7.2.8.1 and 7.2.8.2, the amount of spare capacity that is forecast to occur is very small. Certainly, the maximum estimated idled capacity is smaller than the range of uncertainty in the demand forecast upon which it is based.

Table D-3

SUMMARY OF REQUIREMENTS AND FLOW ADJUSTMENTS
VOLUMES IN 10^9 m^3

YEAR	EAST OF ALBERTA REQUIREMENTS					
	1	2	3	4	5	6
	DEMAND EAST OF ALBERTA	EASTERN EXPANSION	CURRENT TO	EXPORTS TO MIDWESTERN OTHERS	TOTAL EXPORT (3+4)	TOTAL REQUIREMENTS (1+2+5)
1980	29.69	0.00	2.60	4.53	7.13	36.82
1981	30.44	0.45	1.59	4.48	6.07	36.96
1982	31.06	1.39	1.59	4.48	6.07	38.52
1983	31.84	2.12	1.59	4.48	6.07	40.03
1984	32.98	2.87	1.59	4.48	6.07	41.92
1985	34.04	3.70	1.59	4.48	6.07	43.81
1986	34.87	4.04	1.59	4.29	5.88	44.79
1987	35.76	4.43	1.59	4.29	5.88	46.07
1988	36.57	4.79	1.59	4.32	5.91	47.27
1989	37.52	5.18	1.59	3.98	5.57	48.27
1990	38.55	5.60	0.06	3.70	3.76	47.91
1991	39.41	5.82	0.00	1.50	1.50	46.74
1992	40.61	6.07	0.00	0.22	0.22	46.91
1993	41.92	6.32	0.00	0.22	0.22	48.47
1994	43.37	6.60	0.00	0.22	0.22	50.19

The following are taken from the 1979 Gas Report.

-COLUMN 1 is taken from Appendix 4-A, Page 1 of 11, COLUMN 7

-COLUMN 2 is taken from Appendix 4-A, page 1 of 11, COLUMN 8

-COLUMN 3 is taken from Appendix 4-B, the sum of Licences GL-1,

GL-18 and GL-39

-COLUMN 5 is taken from Appendix 4-A, Page 1 of 11, COLUMN 9 less

"TCPPL Makeup" from Appendix 4-B

NOTE: Volumes from the above appendices are converted to cubic meters
by dividing by TransCanada's GHV of 37.86 MJ/m

Table D-4

SUMMARY OF NEW EXPORTS
9 3
VOLUMES IN 10 m

YEAR	1 CONSOLIDATED	EXPORTS BY				6 TOTAL (1+2+3+4+5)
		2 NIAGARA	3 PROGAS	4 SULPETRO	5 TRANSCANADA	
1980	0.35	0.10	0.52	0.72	1.13	2.82
1981	2.07	0.09	3.10	0.61	2.10	7.97
1982	2.07	0.09	3.10	0.51	2.10	7.87
1983	2.07	0.09	3.10	0.00	2.10	7.36
1984	1.98	0.09	2.97	0.00	2.10	7.14
1985	1.46	0.09	2.20	0.00	1.36	5.11
1986	0.95	0.13	1.42	0.00	0.00	2.50
1987	0.43	0.06	0.65	0.00	0.00	1.14
1988	0.00	0.00	0.00	0.00	0.00	0.00
1989	0.00	0.00	0.00	0.00	0.00	0.00
1990	0.00	0.00	0.00	0.00	0.00	0.00
1991	0.00	0.00	0.00	0.00	0.00	0.00
1992	0.00	0.00	0.00	0.00	0.00	0.00
1993	0.00	0.00	0.00	0.00	0.00	0.00
1994	0.00	0.00	0.00	0.00	0.00	0.00

Table D-5

TRANSCANADA PIPELINES
THROUGHPUT REQUIREMENTS FOR THE WESTERN SECTION
BASE CASE
VOLUMES IN 10^9 m^3

YEAR	1 TOTAL EAST OF ALBERTA REQUIREMENTS	2 NEW EXPORTS	3 MANY ISLANDS	4 PRODUCTION EAST OF ALBERTA (1+2+3)	5 TOTAL TRANS- PORTATION	6 TOTAL REQUIRE- MENTS (4+5)	7 FUEL	8 WESTERN SECTION DELIVERIES (6-7)
1980	36.82	0.00	0.56	1.48	1.20	35.99	1.80	34.19
1981	36.96	0.00	0.58	1.42	1.25	36.21	1.81	34.40
1982	38.52	0.00	0.67	1.39	1.31	37.77	1.89	35.88
1983	40.03	0.00	0.72	1.36	1.31	39.25	1.96	37.28
1984	41.92	0.00	0.81	1.28	1.31	41.14	2.06	39.08
1985	43.81	0.00	0.78	1.17	1.31	43.17	2.16	41.02
1986	44.79	0.00	0.70	1.25	1.31	44.15	2.21	41.94
1987	46.07	0.00	0.61	1.34	1.31	45.43	2.27	43.16
1988	47.27	0.00	0.53	1.17	1.31	46.88	2.34	44.53
1989	48.27	0.00	0.47	1.06	1.31	48.05	2.40	45.65
1990	47.91	0.00	0.42	0.97	1.31	47.83	2.39	45.43
1991	46.74	0.00	0.39	0.86	1.31	46.80	2.34	44.46
1992	46.91	0.00	0.33	0.81	1.31	47.07	2.35	44.72
1993	48.47	0.00	0.31	0.75	0.84	48.24	2.41	45.83
1994	50.19	0.00	0.28	0.64	0.84	50.11	2.51	47.60

NOTES:

COLUMN 1 is taken from COLUMN 6, TABLE D-3

FUEL = $0.05 \times$ COLUMN 6

Table D-6

TRANSCANADA PIPELINES
THROUGHPUT REQUIREMENTS FOR THE CENTRAL
SECTION AND GREAT LAKES PIPELINES
BASE CASE
VOLUMES IN 10⁹ m³

YEAR	FLOWS FROM WESTERN SECTION						GREAT LAKES FLOWS						CENTRAL SECTION
	1 WESTERN SECTION DELIVERIES	2 SPC PORTATION	3 EXPORTS TO MIDWESTERN	4 GL-1 EXT.	5 MANITOBA SALES	6 TOTAL SALES EAST OF WINNIPEG (1-2-3-4-5)	7 GREAT LAKES CAPACITY	8 CONSOLIDATED RE-EXPORT	9 T.C.P.L. EXPORTS	10 CANADIAN DELIVERIES	11 TOTAL GREAT LAKES (8+9+10)		
1980	34.19	0.84	2.60	0.00	1.95	28.80	13.46	0.36	3.89	9.21	13.46	15.35	
1981	34.40	0.78	1.59	0.00	1.98	30.05	13.46	0.47	3.89	9.09	13.46	16.60	
1982	35.88	0.84	1.59	0.00	2.03	31.43	13.46	0.47	3.89	9.09	13.46	17.97	
1983	37.28	0.84	1.59	0.00	2.06	32.80	13.46	0.47	3.89	9.09	13.46	19.34	
1984	39.08	0.84	1.59	0.00	2.14	34.52	13.46	0.47	3.89	9.09	13.46	21.06	
1985	41.02	0.84	1.59	0.00	2.23	36.36	13.46	0.47	3.89	9.09	13.46	22.91	
1986	41.94	0.84	1.59	0.00	2.26	37.26	13.46	0.47	3.89	9.09	13.46	23.81	
1987	43.16	0.84	1.59	0.00	2.31	38.42	13.46	0.47	3.89	9.09	13.46	24.97	
1988	44.53	0.84	1.59	0.00	2.37	39.74	13.46	0.47	3.89	9.09	13.46	26.29	
1989	45.65	0.84	1.59	0.00	2.42	40.80	13.46	0.47	3.89	9.09	13.46	27.34	
1990	45.43	0.84	0.06	0.00	2.51	42.03	13.46	0.47	3.89	9.09	13.46	28.58	
1991	44.46	0.84	0.00	0.00	2.56	41.06	13.46	0.47	1.25	9.29	11.02	30.04	
1992	44.72	0.84	0.00	0.00	2.62	41.27	13.46	0.47	0.00	9.29	9.77	31.50	
1993	45.83	0.84	0.00	0.00	2.70	42.29	13.46	0.00	0.00	9.29	9.29	33.00	
1994	47.60	0.84	0.00	0.00	2.79	43.98	13.46	0.00	0.00	9.29	9.29	34.69	

NOTES:

COLUMN 1 is taken from COLUMN 8, TABLE D-5
COLUMN 3 is taken from COLUMN 3, TABLE D-3

Table D-7

TRANSCANADA PIPELINES
THROUGHPUT REQUIREMENTS FOR THE WESTERN SECTION
EXPORT CASE
VOLUMES IN 10^9 m^3

YEAR	1 TOTAL EAST OF ALBERTA REQUIREMENTS	2 NEW EXPORTS	3 MANY ISLANDS	4 PRODUCTION EAST OF ALBERTA (1+2+3)	5 TOTAL TRANS- PORTATION	6 TOTAL REQUIRE- MENTS (4+5)	7 FUEL	8 WESTERN SECTION DELIVERIES (6-7)
1980	36.82	2.81	0.56	1.48	1.20	38.80	1.94	36.86
1981	36.96	7.97	0.58	1.42	1.25	44.18	2.21	41.97
1982	38.52	7.86	0.67	1.39	1.31	45.63	2.28	43.35
1983	40.03	7.35	0.72	1.36	1.31	46.60	2.33	44.27
1984	41.92	7.14	0.81	1.28	1.31	48.28	2.41	45.86
1985	43.81	5.11	0.78	1.17	1.31	48.28	2.41	45.87
1986	44.79	2.49	0.70	1.25	1.31	46.64	2.33	44.31
1987	46.07	1.13	0.61	1.34	1.31	46.56	2.33	44.24
1988	47.27	0.00	0.53	1.17	1.31	46.88	2.34	44.53
1989	48.27	0.00	0.47	1.06	1.31	48.05	2.40	45.65
1990	47.91	0.00	0.42	0.97	1.31	47.83	2.39	45.43
1991	46.74	0.00	0.39	0.86	1.31	46.80	2.34	44.46
1992	46.91	0.00	0.33	0.81	1.31	47.07	2.35	44.72
1993	48.47	0.00	0.31	0.75	0.84	48.24	2.41	45.83
1994	50.19	0.00	0.28	0.64	0.84	50.11	2.51	47.60

NOTES:

COLUMN 1 is taken from COLUMN 6, TABLE D-3

COLUMN 2 is taken from COLUMN 6, TABLE D-4

FUEL = 0.05 x COLUMN 6

TRANSCANADA PIPELINES
THROUGHPUT REQUIREMENTS FOR THE CENTRAL
SECTION AND GREAT LAKES PIPELINES
EXPORT CASE
VOLUMES IN 10^9 m^3

YEAR	FLOWS FROM WESTERN SECTION						GREAT LAKES FLOWS								
	1 WESTERN SECTION DELIVERIES	2 SPC TRANS- PORTATION	3 EXPORTS TO MIDWESTERN CURRENT	4 EXPORTS TO GL-1 EXT.	5		6 TOTAL SALES EAST OF WINNIPEG (1-2-3-4-5)	7 GREAT LAKES CAPACITY	8		10 CANADIAN DELIVERIES	11 TOTAL GREAT LAKES (8+9+10)	12 CENTRAL SECTION		
					MANITOBA				CONSOLIDATED					T.C.P.L.	
					SALES				RE-EXPORT					EXPORTS	
1980	36.86	0.84	2.60	1.13	1.95	30.34	13.46	0.36	4.75	8.34	13.46	16.89			
1981	41.97	0.78	1.59	2.10	1.98	35.53	13.46	0.47	9.06	3.93	13.46	22.07			
1982	43.35	0.84	1.59	2.10	2.03	36.80	13.46	0.47	9.06	3.93	13.46	23.34			
1983	44.27	0.84	1.59	2.10	2.06	37.69	13.46	0.47	9.06	3.93	13.46	24.23			
1984	45.86	0.84	1.59	2.10	2.14	39.20	13.46	0.47	8.84	4.14	13.46	25.74			
1985	45.87	0.84	1.59	1.36	2.23	39.86	13.46	0.47	7.55	5.43	13.46	26.40			
1986	44.31	0.84	1.59	0.00	2.26	39.63	13.46	0.47	6.26	6.73	13.46	26.18			
1987	44.24	0.84	1.59	0.00	2.31	39.50	13.46	0.47	4.96	8.02	13.46	26.04			
1988	44.53	0.84	1.59	0.00	2.37	39.74	13.46	0.47	3.89	9.09	13.46	26.29			
1989	45.65	0.84	1.59	0.00	2.42	40.80	13.46	0.47	3.89	9.09	13.46	27.34			
1990	45.43	0.84	0.06	0.00	2.51	42.03	13.46	0.47	3.89	9.09	13.46	28.58			
1991	44.46	0.84	0.00	0.00	2.56	41.06	13.46	0.47	1.25	9.29	11.02	30.04			
1992	44.72	0.84	0.00	0.00	2.62	41.27	13.46	0.47	0.00	9.29	9.77	31.50			
1993	45.83	0.84	0.00	0.00	2.70	42.29	13.46	0.00	0.00	9.29	9.29	33.00			
1994	47.60	0.84	0.00	0.00	2.79	43.98	13.46	0.00	0.00	9.29	9.29	34.69			

NOTES:

COLUMN 1 is taken from COLUMN 8, TABLE D-7

COLUMN 3 is taken from COLUMN 3, TABLE D-3

COLUMN 5, is taken from COLUMN 5, TABLE D-4

COLUMN 9 is the sum of COLUMNS 1 and 3, TABLE D-4 plus COLUMN 9, TABLE D-6

APPENDIX E

TREATMENT OF EXPORTS
Table E-1

REMAINING QUANTITIES

IN EXISTING LICENCES

			Remaining Quantities*	
			(10 ⁶ m ³)	(PJ)
SOUTH FROM ALBERTA	A&S	GL- 3	29 889	1 158.4
		GL-16	19 574	758.6
		GL-24	29 212	1 132.1
		GL-35	11 420	442.6
	CMPL	GL- 5	2 026	77.6
		GL-17	2 022	77.4
		GL-25	1 402	53.7
		GL-36	693	26.5
	GO- 3		113	4.2
		WTCL GL- 4	5 467	211.9
TOTAL SOUTH		101 818	3 943.0	
BRITISH COLUMBIA	WTCL	GL-41	88 677	3 453.2
EAST OF ALBERTA	ICG	GL-28	153	5.8
		GL-29	3 625	137.2
	NGTL	GL- 6	1 097	41.6
		TCPL	GL- 1	972
	GL-18		18 579	703.4
	GL-19	1 824	69.1	
	GL-20	11 896	450.4	
	GL-37	22 073	835.7	
	GL-38	5 648	213.8	
	GL-39	813	30.8	
	GL-43	8 156	308.8	
	TOTAL EAST		74 836	2 833.4
CANADA	TOTAL		265 331	10 229.6

*Estimated as of Dec. 31, 1979

		ALLOWANCE GIVEN EXISTING LICENCES (PETAJOULES)															
		1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
SOUTH FROM ALBERTA	A+S																
	GL-3 ^{*(1)}	184.3	183.8	183.8	183.8	184.3	183.8	153.1									
	GL-16 ^{*(2)}	90.9	90.7	90.7	90.7	90.9	90.7	90.7	90.7	90.9	21.2						
	GL-24 ^{*(1)}	94.8	94.6	94.6	94.6	94.8	94.6	94.6	94.6	94.8	94.6	94.6	87.0	49.0	40.8		
	GL-35 ^{*(1)}	82.4	82.1	82.1	82.1	82.4	68.4										
CMPL	GL-5 ^{*(1)}	20.8	20.8	17.5	14.3	14.3	11.9										
	GL-17 ^{*(2)}	13.9	13.8	11.7	9.5	9.5	9.5	9.5	9.5	9.5	3.9						
	GL-25 ^{*(2)}	9.5	9.5	9.5	9.5	9.5	9.5	4.7									
	GL-36 ^{*(1)}	4.8	4.8	4.8	4.8	4.8	4.0										
	GO-3 ^{*(2)}	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4						
WTCL	GL-4 ^{*(1)}	61.1	57.4														
	TOTAL SOUTH	562.9	557.9	495.0	489.6	491.0	475.1	364.8	195.1	195.7	120.0	94.6	87.0	49.0	40.8		
BRITISH COLUMBIA																	
WTCL	GL-41 ^{*(1)}	326.7	325.8	325.8	325.8	326.7	325.8	325.8	325.8	326.7	271.4						
EAST OF ALBERTA	ICG																
	GL-28 ^{*(2)}	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.9
NGTL	GL-29 ^{*(2)}	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	10.5
	GL-6 ^{*(2)}	7.0	7.0	7.0	7.0	7.0	6.7										
TCPL	GL-1 ^{*(1)}	36.8															
	GL-18 ^{*(1)}	59.3	59.1	59.1	59.1	59.3	59.1	59.1	59.1	59.3	49.2						
	GL-19 ^{*(2)}	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	4.3						
	GL-20 ^{*(1)}	36.9	36.8	36.8	36.8	36.9	36.8	36.8	36.8	36.9	36.8	36.8	30.6				
	GL-37 ^{*(1)}	76.9	76.7	76.7	76.7	76.9	76.7	76.7	76.7	76.9	76.7	76.7	63.8				
	GL-38 ^{*(1)}	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	16.3				
	GL-39 ^{*(1)}	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.4					
	GL-43 ^{*(1)}	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	15.2				
CANADA																	
TOTAL EAST		278.3	241.0	241.0	241.0	241.5	240.7	234.0	234.0	234.5	221.4	151.3	59.6	13.8	13.8	13.8	11.5
TOTAL		1167.9	1124.6	1061.8	1056.4	1059.1	1041.6	924.6	754.9	756.9	612.8	245.9	146.5	62.8	54.5	13.8	11.5

* Including provision for annual averaging at maximum daily licensed rate (adjusted for heat content), times the number of days in the year, as permitted by existing conditions in the licence.

** Assuming export at maximum annual licensed rate (adjusted for heat content).

(1) Allowance was made for annual exports until the expiry of the term of the licence.

(2) Allowance was made for annual exports until that point in time at which the remaining term volumes would have been exhausted if the licensee were to export at the level of the annual licensed quantity (without recourse to any annual averaging permitted in the licence).

ALLOWANCE GIVEN
APPLIED FOR QUANTITIES
(Petajoules)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
SOUTH FROM ALBERTA																
A&S GL-3							28.1	168.3	168.3	140.2						
GL-35						12.4	74.1	74.1	74.1	61.7						
CMPL GL-5	-6.2*	-6.3*	-3.1*				2.0	11.9	11.9	9.9						
GL-17	-4.2*	-4.1*	-2.1*							2.7						
GL-25							3.2	7.9	7.9	7.9	7.9	7.4	4.5	3.8		
GL-36						0.6	4.0	4.0	4.0	3.3						
ADEN	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4							
WTCL GL-4	3.4	3.4	56.0	56.0	56.0	56.0	56.0	56.0	56.0	46.6						
PAWEST	16.2	97.2	97.2	97.2	97.2	97.2	97.2	97.2	97.2	97.2	97.2	97.2	97.2	97.2	80.9	269.8
PAEAST	54.1	54.1	323.9	323.9	323.9	323.9	323.9	323.9	323.9	323.9	323.9	323.9	323.9	323.9	323.9	269.8
TOTAL SOUTH	16.2	154.7	482.3	487.5	487.5	500.5	598.9	753.7	743.3	693.4	429.0	428.5	425.6	424.9	404.8	269.8
BRITISH COLUMBIA																
WTCL GL-41										25.6	266.5	244.5	222.4	200.4	178.3	133.2
COLUMBIA	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	
TOTAL B.C.	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	39.9	280.8	258.8	236.7	214.7	192.6	133.2
EAST FROM ALBERTA																
SULPETRO	23.2	23.2	23.2	78.3	78.3	75.7	60.0	44.4	28.7	13.0						
CNG	13.1	78.3	78.3	79.4	79.4	75.7										
TCPL	42.6	79.4	79.4	3.4	3.4	3.7	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	8.6
NIAGARA	3.4	3.4	3.4	117.4	117.4	114.2	89.6	66.2	43.7	19.2						
PROGAS	19.6	117.4	117.4	278.5	278.5	269.3	160.0	121.0	82.8	42.6	10.4	10.4	10.4	10.4	10.4	8.6
TOTAL EAST	101.9	301.7	301.7	780.3	780.3	784.1	773.2	889.0	840.4	775.9	720.2	697.7	672.7	650.0	607.8	411.6
CANADA	132.4	470.7	798.3	780.3	780.3	784.1	773.2	889.0	840.4	775.9	720.2	697.7	672.7	650.0	607.8	411.6

■ represents the removal of the allowance given by the Board for conditions in Licences GL-5 and GL-17 which authorize yearly quantities of 84 983 500 m³ and 56 655 700 m³ respectively.

COST-BENEFIT ANALYSIS OF BOARD DECISION1. Introduction

Before granting new licences to export natural gas, the Board determines inter alia that such exports are in the public interest. Among considerations the Board takes into account is whether such new exports will benefit Canadians.

One means of assisting in the evaluation of the net benefits to Canada from the export of natural gas is to assess proposed exports within the framework of a cost-benefit analysis. An advantage of using this form of analysis is that the Board can measure the direct benefits and costs resulting from the export sale against the alternative of keeping the natural gas in Canada and using it to meet Canadian requirements in some future period.

Of course, factors outside of cost-benefit analysis are also important to the Board's decision. These include difficult-to-quantify elements such as environmental impacts, the overall effect on the producing industry, the merit of special considerations such as border accommodation to reflect the long-standing spirit of friendship between Canada and the United States, and regional or macroeconomic impacts.

2. Purpose of the Board's Cost-Benefit Analysis

The Board's cost-benefit analysis estimates the (direct) net economic benefits to Canadian society that would result from new exports of natural gas compared with the alternative of keeping the gas to meet Canadian requirements in some future period.

While theoretically cost-benefit analysis could include consideration of environmental and other difficult-to-quantify costs and benefits, the Board has viewed cost-benefit analysis as an attempt to measure only the direct economic effects from the proposed exports, albeit from the perspective of society as a whole.

Cost-benefit analysis considers a project from the viewpoint of society and costs are included only if they truly represent the use of capital, labour, or other real resources due to the proposed exports.

Payments incurred for expenses such as taxes are considered as transfers within the economy, and therefore are not considered costs to society.

3. Approach of the Board

Considerable caution is required in evaluating the cost-benefit results as submitted by the various Applicants. Each submission contains numerous assumptions, and the separate methodologies, while generally similar, differ significantly with respect to the handling of certain issues. Applicants' submissions have been summarized in Chapter 5.

In order to measure the various export proposals from a common basis and in order to be able to evaluate a number of alternative assumptions, the Board has undertaken its own cost-benefit analyses. In estimating costs and benefits, the Board relied upon evidence from the hearing, supplemented where necessary by its own knowledge of the gas production and transmission industry. For certain major cost and benefit items the Board considered a range of values, some of which are discussed below.

The conceptual approach adopted by the Board was to identify first the costs and benefits that would result if no new natural gas exports were authorized. The Board then estimated the costs and benefits that would result if a particular application for additional natural gas exports were granted. The annual net benefits of the proposed exports were calculated as the difference between the annual cash flows that would result if the gas were exported as proposed, and the annual cash flows that would occur if such gas were retained in Canada to meet future domestic requirements. Annual net benefits were then discounted to a present value.

Estimated benefits of each export proposal were derived from the assumed revenue from the sale of natural gas in the export market plus the value of associated by-products.

The costs directly associated with producing and delivering the proposed volumes to the export market included any incremental capital and operating expenditures that would be needed as a result of the export proposal. These resource costs included costs for development, field equipment, natural gas processing plants, and gathering systems, as well as transmission costs attributable to additions to pipeline systems, and additional operation, maintenance, and fuel gas costs. Costs incurred to date were viewed as sunk costs and were not included in the analysis. The Board also evaluated the additional costs associated with new Canadian gas supplies and estimated the incremental cost to Canadians of having to use higher cost gas in the future as a result of exports over the near term.

An additional cost of exports was assessed as the value of the decline in the "inventory" of established marketable reserves of natural gas which would be brought about by increased exports.

It may be noted that the Board has not separated estimated net economic benefits between recipients, Canadian and foreign. However, Canadians receive a substantial part of any net benefits through their Provincial Governments as taxes and royalties, through the Federal Government as taxes, and through equity ownership in public or private businesses and corporations as profits.

The Board's base case includes "best guess" assumptions with respect to future finding, producing, and transmission costs, and other factors. To test the robustness of the results, the Board also completed a sensitivity analysis, in which all cost factors were assumed to be higher. The Board also tested its results using changed assumptions with respect to natural gas prices. All cases were evaluated using real discount rates of five, ten, and fifteen percent.

4. The Board's Analysis of the Export Proposals

The Board's estimates of the Applicant's individual export proposals are presented in Table F-1. These results are based on the assumption that only the specific export proposal under study is authorized; consideration is not given to whether the proposed exports would accord with the Board's surplus tests.

TABLE F-1
SUMMARY OF BOARD'S ESTIMATES OF COSTS AND BENEFITS OF VARIOUS
EXPORT PROPOSALS ON A SINGLE APPLICATION BASIS
(Present value millions of 1978 dollars discounted at 10% to 1979)

<u>Export Proposal</u>	<u>Volumes</u> (10 ⁹ m ³)	<u>Benefits</u> (1)	<u>Costs</u> (2)	<u>Net Economic Benefits</u> (3)=(1)-(2)
Alberta & Southern - extension	20.7	1,041	353	688
Canadian-Montana - new licence	2.3	175	21	154
Canadian-Montana - reinstatement volumes	1.7	82	20	62
Canadian-Montana - extension	1.3	68	19	49
Columbia Gas	5.8	337	77	260
Consolidated Natural Gas	14.5	1,060	429	631
Niagara Gas	3.2	154	40	114
Pan-Alberta (incremental) 14-year term	139.9	7,564	2,775	4,789
Pan-Alberta (stand alone) 14-year term	139.9	7,542	2,997	4,545
ProGas	21.7	1,598	667	931
Sulpetro	1.9	185	56	129
TransCanada GL-1 - extension	11.6	958	293	665
Westcoast GL-4* - extension	7.9	560	93	467
Westcoast GL-41 - El Paso	6.2	447	113	334
Westcoast GL-41* - extension	33.1	1,108	356	752

Note: Gas export price of 2.61 (U.S.) per GJ assumed in above calculations.

* Export Volumes included additional term volumes requested in the application and make-up volumes.

The projects differ significantly in size and, in general, the larger export proposals are estimated to provide the greater absolute net economic benefits. However, the Board's analysis indicates that each of the proposals would yield net economic benefits to Canada.

Because the Applicants generally assumed that the future export border price would remain at the level prevailing at the time of preparation of their cost-benefit analyses, the Board in the analysis of the individual applications reported in Chapter 5 and in Table F-1 estimated net economic benefits assuming an export border price equal to that prevailing at the time of the hearing, i.e. \$2.61 (U.S.) per gigajoule. For the approved new exports the Board has also undertaken analysis using the current export border price of \$3.22 (U.S.) per gigajoule.

5. Net Benefits of New Exports Approved by the Board

For the new exports which the Board has approved, an estimate of net benefits has been calculated reflecting the quantity and licence term conditions imposed by the Board. Results are summarized in Table F-2.

Net economic benefits resulting from the approved new exports are estimated to be about \$5 billion assuming a gas export border price of \$2.61 (U.S.) per gigajoule, the border price existing at the time of the hearing; or about \$6.6 billion if calculated on the basis of the current export border price of \$3.22 (U.S.) per gigajoule.

To estimate net economic benefits of exports arising from the Board's decision it was necessary to group the various approved new licences by pipeline system.

Several general conclusions are apparent. The Pan-Alberta export, with significantly larger volumes than the other new exports generates the largest total net economic benefits. On a per-unit exported basis, the greatest net benefits are those from exports utilizing existing systems, as would be expected. But, as noted elsewhere in this report, the Board would not expect Canadians to bear the cost of excess capacity in the prebuilt facilities of Foothills related to the Pan-Alberta exports. To the extent that such costs are allocated differently the economic benefits of the Pan-Alberta exports would be greater.

Table F-2

SUMMARY OF THE BOARD'S ESTIMATES OF COSTS AND BENEFITS
OF APPROVED NEW EXPORTS*

(Present Value millions of 1978 dollars discounted at 10% to 1979)

	<u>New Export Volumes</u>	<u>Benefits</u>	<u>Costs</u>	<u>Net Economic Benefits</u>
	(10 ⁹ m ³)	(1)	(2)	(3)=(1)-(2)
Exports via TCPL	41.6	4048	1370	2678
Exports via Westcoast	2.4	235	60	175
Exports via Foothills	52.3	4794	1758	3036
Exports via Other	10.7	879	202	677
Total Exports	107	9956	3390	6566

* Gas Export Price of \$3.22 (US) per gigajoule assumed in above calculations. With a gas export price of \$2.61 (US) per gigajoule, net economic benefits are estimated at \$5,006 million.

To assure itself that these economic benefits to Canadians would be realized, even if circumstances differ significantly from those presently foreseen, the Board has considered estimates of economic benefits under a range of costs and future prices.

First, a range of higher real export gas prices are considered. Table F-3 shows the results of price increases at the rate of three and four percent per year. Such increases imply a more than doubling of the real price of export gas by the year 2000. Even under these circumstances there will be substantial net economic benefits to Canada flowing from the export decision. As indicated, this is true under a wide range of discount rates. However, the Board notes that should future real gas prices rise persistently, the absolute level of net economic benefits from current exports depends principally upon a comparison between the expected rate of increase in gas export prices and the discount rate.

Second, a range of costs are considered, shown in Table F-4. Gas finding, producing and transmission costs and the rate of increase in gas replacement costs were doubled over the Board's base case. Such real cost increases are viewed as extremely unlikely particularly since the export project expenditures will occur in Southern Canada. Even with these hypothetically higher costs the estimated net economic benefits would be very large.

Table F-3

ANALYSIS OF THE NET BENEFITS OF
NEW EXPORTS UNDER VARIOUS ASSUMPTIONS
ABOUT FUTURE EXPORT BORDER PRICES
(Present value millions of 1978 dollars)

<u>Future Price Assumptions</u>	<u>Discount Rate</u> (%)	<u>Benefits</u> (1)	<u>Costs</u> (2)	<u>Net Economic Benefits</u> (3)=(1)-(2)
\$3.22 (U.S.)/ GJ and Constant	5 10 15	12679 9956 7947	5428 3390 2690	7251 6566 5255
\$3.22 (U.S.)/ GJ & rising at 3% a year	5 10 15	14386 2475 8946	9631 4219 2889	4755 7031 6057
\$3.22 (U.S.)/ GJ & rising at 4% a year	5 10 15	15010 11723 9311	12292 4726 3003	2718 6997 6308

Table F-4

ANALYSIS OF THE NET BENEFITS* OF NEW EXPORTS
UNDER HIGHER COST ASSUMPTIONS**
(Present value millions of 1978 dollars)

<u>Cost Assumption</u>	<u>Discount Rate</u>	<u>Benefits</u>	<u>Costs</u>	<u>Net Economic Benefits</u>
	(%)	(1)	(2)	(3)=(1)-(2)
Expected Costs	5	12679	5428	7251
	10	9956	3390	6566
	15	7947	2690	5255
If Expected	5	12679	9182	3497
Costs Double	10	9956	6585	3371
	15	7947	5408	2539

* Assumed export border price of \$3.22 (U.S.) per GJ and constant.

** Costs include: capital and operating costs for production and transmission as well as the increased cost to Canadians of exporting, and inventory adjustment costs.

6. Cost-Benefit Conclusions

Generally, under the Board's assumptions of future prices, costs, and the appropriate social discount rate, each of the export proposals are estimated to yield positive net economic benefits to Canada.

The aggregate net economic benefits to Canada arising from the new exports to be approved as a result of the Board's decision are estimated to be \$6.5 billion, assuming the current border price of \$3.22 (U.S.) per GJ.

7. Technical Notes on the Board's Cost-Benefit Analysis

The general assumptions underlying the Board's cost-benefit work are discussed in the following paragraphs. The Board has relied upon evidence obtained during the hearing, which has been supplemented, where necessary, by its own knowledge of the gas production and transmission industry.

By-Product Revenue - The Board accepted the view of several witnesses that the revenue from the sale of by-products associated with natural gas production represents a direct benefit of the export proposals. Although by-products were valued at 30 percent of the value of gas produced in several of the cost-benefit studies submitted, for its cost-benefit work the Board assumed an average value for by-products equivalent to 20 percent of the export border price.

Producers' Costs - The Board considered the Applicants' estimates of producers' incremental capital and operating costs, taking into account any estimates of in-place capacity in its analysis. In those cases where producers' cost estimates were not provided, the Board based its incremental cost estimates on average unit capital costs of \$1.45/GJ of productive capacity added and an average unit operating cost of \$0.19/GJ produced in 1978 dollars. The unit capital costs include allowances of \$0.28/GJ for field equipment and related facilities; \$0.47/GJ for development drilling; and \$0.70/GJ for gas plant facilities.

Incremental Transportation Costs - Several of the parties to the hearing used cost of service estimates in their cost-benefit studies as representative of the resource costs associated with transporting gas to the export border point. For the cost-benefit analysis done by the Board, incremental transportation costs were estimated. Incremental capital expenditures were estimated to be the difference between the capital costs that would be incurred if exports were permitted and the costs that would be incurred in the absence of exports. Incremental operating expenditures were estimated on the basis of operation, maintenance, and fuel gas costs associated with each export proposal.

Gas Replacement Costs - The Board in its cost-benefit study also considered the increased cost to Canadians of having to use higher cost gas sooner than would be the case in the absence of new exports. In estimating these replacement costs, the Board examined the costs associated with exploring and developing new gas supplies in Canada. Over the period 1979 to 2000, many factors will have an impact on the average annual cost to Canadians of natural gas. In particular, currently connected depleting gas fields will have to be replaced with higher cost conventional supplies and eventually with frontier supplies.

Based on the Board's estimates of future annual gas deliverability and requirements, estimates were made of the average annual real resource costs of finding and developing gas in Canada. Exploration activity and subsequent costs were assumed to continue at 1978 levels, but reserves additions were projected at a level that resulted in frontier gas being needed in Canada in the mid-1990's. Thus, implicitly, finding costs per unit were assumed to increase. However, development costs per unit were assumed to remain constant in real terms on the basis that technological advance would offset any tendency for real costs to increase as a result of more difficult or deeper drilling. The resultant pattern of real resource costs per unit was then approximated by a smooth exponential curve to yield an average rate of increase in costs per unit produced in the future.

As noted in Chapter 6, the Board is aware of the uncertainties inherent in forecasting future finding and production costs. Nevertheless, the Board estimates that real replacement costs may rise approximately one percent per 1 055 PJ of gas produced, rising from \$0.54/GJ in 1979 to approximately \$1.04/GJ in 2000. The cost-benefit results are based upon these replacement cost estimates.

Inventory Adjustment Value - While gas replacement costs accounted for the increased cost to Canadians of using higher cost gas sooner as a result of new exports, it is the Board's view that an additional cost to Canadians of exporting natural gas is the foregone benefit associated with retaining the gas for later use by Canada. Several of the parties to the hearing

assessed the foregone benefit by assuming that if exports were not permitted, the export deliverability could be deferred to be called upon at the same rate in the future. In the Board's view, deliverability cannot be deferred in this manner. Instead, it is the development of reserves which is postponed. The approach adopted by the Board to measure the foregone benefit was to estimate the value in the year 2000 of the change in natural gas reserves available in Canada contingent upon exports.

The Board estimated the value to Canadians of natural gas reserves in the year 2000 to be \$0.75/GJ in 1978 dollars based on a real discount rate of ten percent and an export border price of \$3.22 (U.S.) per GJ. The social value of natural gas was arrived at by undertaking a discounted cash flow analysis of the estimated annual revenues and resource costs which would result from producing natural gas reserves available in the year 2000 over the ensuing years.

Indirect Benefits and Costs - The Board did not include in its analysis possible indirect benefits and costs which could be viewed as resulting from the export proposals. For example, any reinvestment of a portion of gas producers' receipts from the proposed exports and the value of assumed incremental discoveries associated with this reinvestment were excluded from the Board's cost-benefit work.

Social Discount Rate - The Board considered a rate of 10 percent to be a reasonable value for the export projects although the Board undertook sensitivity analysis at 5 and 15 percent.

Verification of the Current
Deliverability Test

This Appendix contains details of the Board's forecast of supply and demand and the comparisons the Board made to verify its decision regarding new exports under the Current Deliverability Test. In this Appendix the Board's forecast of deliverability from established reserves in the conventional areas is compared with the Board's forecast of Canadian requirements plus the allowance made for existing export licences and new exports which the Board is prepared to authorize.

The total demand for natural gas in Canada is summarized on Table G-1. The Board included the eastern market expansion demand in the net sales. Fuel requirements associated with the proposed new exports are shown separately. The demand for Canadian gas is shown for each area - Alberta, British Columbia, and East of Alberta on Table G-2.

The forecast of reprocessing shrinkage requirements at the four straddle plants at Cochrane, Empress, Edmonton and Waterton is shown on Table G-3. The forecast was based on the assumption that the existing processing plants would not be expanded beyond the current capacity except for the planned expansion at Empress in 1986.

The forecasts of deliverability from controlled established reserves are summarized by system on Table G-4. The quantities shown in each column supply specific markets discussed in the following paragraphs. Deliverability forecasts for the various sources of supply available to

satisfy demand for Alberta gas including exports south from Alberta are described in Chapter 3. These include: deliverability from Alberta utilities; the Board's estimate of Alberta and Southern's deliverability less its sales to Columbia Natural Gas; the Board's estimate of total supplies available to Westcoast Licence No. GL-4; the Board's estimate of Canadian-Montana's deliverability from its permit fields; the Board's estimate of TransCanada's Alberta sales and its contribution to AGTL fuel and reprocessing shrinkage; the Board's estimate of deliverability from Pan-Alberta's new permit fields; Pan-Alberta (AERCB Permit No. PA 74-1) sales in Alberta; the Board's estimate of Westcoast's

Alberta supply after 1989; the Board's estimate of deliverability from deferred gas reserves; the Board's estimate of deliverability from Alberta uncommitted reserves and from 50 percent of the reserves currently beyond economic reach.

The sum of these forecasts of supply in Alberta is compared to the total demand in Alberta as shown in Column 9 of Table G-5 and when excess quantities are available, they are assumed to supply British Columbia and East of Alberta when these regions require the gas.

To determine the need for this additional Alberta gas in British Columbia, the Board examined the fixed supply sources for British Columbia, which are summarized on Table G-6. These forecasts of supply include the Board's forecast of Westcoast's deliverability from its total supply area including all established reserves in British Columbia, the southern Territories and its Alberta supply area; the Board's forecast of deliverability available from Pan-Alberta's reserves after making allowances for Pan-Alberta's sales in Alberta and east of Alberta and to Westcoast in respect of Licence GL-4; the Board's forecast of Alberta and Southern sales to Columbia Natural Gas; and the Board's forecast of deliverability from uncommitted British Columbia supply. Comparing this forecast of deliverability with the total British Columbia demand, including the authorized exports at Huntingdon, the Board concluded that there will be deficiencies in deliverability from established reserves in British Columbia in certain years of the forecast. These deficiencies in British Columbia are treated as demands on surplus Alberta deliverability when available. These deficiencies can be essentially satisfied by surplus Alberta deliverability until about 1989 as shown in Table G-10.

Before allocating any of the Alberta surplus deliverability to British Columbia, the Board determined the need for surplus Alberta deliverability east of Alberta. The forecasts of deliverability from sources that supply markets east of Alberta are summarized in Table G-7. These forecasts include: the Board's forecast of deliverability from TransCanada's controlled reserves less the Board's estimate of

TransCanada's Alberta Sales; the Board's forecast of the AGTL fuel requirements to transport TransCanada's gas; the Board's forecast of total reprocessing shrinkage at Empress based on the Board's forecast of TransCanada throughput; Saskatchewan Power Corporation's forecast of Many Islands Pipelines' deliverability; the Board's forecast of Pan-Alberta sales east of Alberta; production east of Alberta as discussed in Chapter 3; the Board's forecast of deliverability from reserves controlled by Sulpetro; and the Board's forecast of deliverability from reserves controlled by ProGas. This total forecast of supply is capable of satisfying total demand east of Alberta including authorized exports and proposed new exports as shown on Table G-11 up to and including 1988 for all practical purposes. The first significant requirement for additional Alberta gas to be contracted by suppliers of demand east of Alberta occurs in 1987.

Gas deliverability which is surplus to Alberta requirements is allocated to British Columbia and east of Alberta as shown in Table G-8. The Board assumed that the necessary additional capacity in available pipelines connecting British Columbia with Alberta reserves would be constructed when required. It can be seen from Table G-8 that after satisfying demand in British Columbia and east of Alberta from 1980 to 1987, there would remain quantities of gas, shown in column 8, which would provide a temporary surplus for future use. In Table G-8 these quantities were assumed not to be produced between 1980 and 1987 and are converted as required to a forecast of deliverability starting in 1988 and allocated to British Columbia and east of Alberta based on the proportion of unsatisfied demand attributable to each of these regions.

Since the Board deferred deliverability from the temporary overall surplus supplies between 1980 and 1987 until 1988 and later, adjustments had to be made to the Board's forecast of deliverability from uncommitted reserves. The total effect of these adjustments to the forecast is detailed on Table G-9.

The Board's total Canadian supply/demand balance is shown in Table G-12. Deliverability from established reserves in conventional areas is estimated by the Board to be capable of meeting total Canadian demand plus authorized exports and proposed new exports until a deficiency appears in 1988.

TOTAL DEMAND FOR CANADIAN NATURAL GAS

(PETAJOULES/YEAR)

YEAR	DOMESTIC				EXPORT				
	(1) NET SALES	(2) DOMESTIC FUEL	(3) NET REPROC	(4) FUEL FOR EXPORTS	(5) TOTAL DOMESTIC (1+2+3+4)	(6) EXISTING EXPORTS	(7) NEW EXPORTS	(8) FUEL NEW EXPORTS	(9) TOTAL DEMAND (5+6+7+8)
1980	1708	112	207	40	2067	1168	137	9	3381
1981	1779	117	207	40	2143	1125	471	29	3767
1982	1861	123	210	35	2229	1062	794	35	4120
1983	1950	129	210	35	2323	1056	780	33	4193
1984	2043	137	210	35	2424	1059	752	32	4267
1985	2143	144	212	35	2534	1042	556	23	4155
1986	2183	149	239	33	2603	925	370	14	3912
1987	2243	153	236	28	2661	755	204	7	3626
1988	2314	158	232	27	2731	757	0	0	3488
1989	2375	163	219	27	2784	613	0	0	3397
1990	2443	168	218	12	2841	246	0	0	3087
1991	2505	173	218	4	2900	147	0	0	3046
1992	2578	181	227	2	2987	63	0	0	3050
1993	2672	186	228	2	3087	55	0	0	3141
1994	2756	192	228	0	3176	14	0	0	3190
1995	2847	199	229	0	3275	12	0	0	3287
1996	2929	206	231	0	3367	0	0	0	3367
1997	3019	214	231	0	3464	0	0	0	3464
1998	3116	222	231	0	3568	0	0	0	3568
1999	3215	230	231	0	3675	0	0	0	3675
2000	3319	239	232	0	3789	0	0	0	3789
TOTAL	51996	3594	4684	355	60629	10096	4064	182	74968

-FIGURES MAY NOT ADD DUE TO ROUNDING.

-COLUMN 1 IS THE TOTAL DOMESTIC NET SALES IN CANADA AS SHOWN IN TABLE 4.3B.

-COLUMN 2 IS THE FUEL FOR THE DOMESTIC NET SALES.

-COLUMN 3 IS THE TOTAL REPROCESSING SHRINKAGE FROM COLUMN 5, TABLE G-3.

-COLUMN 4 IS THE FUEL FOR THE EXISTING EXPORTS.

-COLUMN 6 IS THE EXISTING EXPORTS NOT INCLUDING FUEL.

-COLUMN 7 IS THE TOTAL NEW EXPORTS FROM TABLE 9.1 ADJUSTED FOR THE ALLOWANCE, SHOWN IN TABLE E-3, GIVEN BY THE BOARD FOR CONDITIONS IN LICENCES GL-5 AND GL-17.

-COLUMN 8 IS THE INCREMENTAL FUEL FOR THE NEW EXPORTS.

DEMAND FOR CANADIAN GAS BY AREAS

(FETAJOULES/YEAR)

YEAR	ALBERTA			BRITISH COLUMBIA			EAST OF ALBERTA			TOTAL CANADA		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	DOMESTIC	EXPORT	AGTL FUEL	NET REPROC	DOMESTIC	EXPORT	BASE CASE EXPANSION	DOMESTIC	EXPORT	DOMESTIC	EXPORT	TOTAL
										(1+3+4+5+7+8)	(2+6+9)	(10+11)
1980	515	579	25	207	196	342	1124	0	393	2067	1314	3381
1981	536	716	25	207	206	341	1152	17	568	2143	1624	3767
1982	551	987	24	210	216	341	1176	53	563	2229	1891	4120
1983	577	987	24	210	228	341	1205	80	542	2323	1870	4193
1984	591	968	25	210	242	342	1248	109	534	2424	1843	4267
1985	612	834	25	212	257	337	1289	140	450	2534	1621	4155
1986	604	639	24	239	262	333	1321	153	337	2603	1309	3912
1987	615	355	22	236	266	330	1354	167	281	2661	965	3626
1988	639	195	23	232	271	327	1385	182	235	2731	756	3488
1989	649	120	23	219	277	271	1420	196	221	2784	612	3397
1990	659	95	22	218	271	0	1459	212	151	2841	246	3087
1991	669	87	20	218	280	0	1492	221	60	2900	147	3046
1992	681	49	20	227	291	0	1538	230	14	2987	63	3050
1993	709	41	21	228	303	0	1587	239	14	3087	55	3141
1994	721	0	21	228	315	0	1642	250	14	3176	14	3190
1995	734	0	22	229	329	0	1702	261	12	3275	12	3287
1996	742	0	22	231	342	0	1762	268	0	3367	0	3367
1997	750	0	23	231	356	0	1828	275	0	3464	0	3464
1998	759	0	24	231	372	0	1901	282	0	3568	0	3568
1999	767	0	25	231	388	0	1977	288	0	3675	0	3675
2000	774	0	26	232	405	0	2056	296	0	3789	0	3789
TOTAL	13852	6649	486	4684	6072	3304	31617	3918	4386	60629	14339	74968

-FIGURES MAY NOT ADD DUE TO ROUNDING.

-COLUMNS 1 PLUS 3 REPRESENT THE TOTAL DOMESTIC DEMAND FOR GAS IN ALBERTA. COLUMN 1 INCLUDES THE FUEL AND LOSSES FOR DISTRIBUTION OF ALBERTA'S NET SALES OF GAS. COLUMN 3 IS THE FUEL REQUIREMENTS FOR AGTL FOR ALL GAS (EXCLUDING NEW EXPORTS) TRANSPORTED IN ITS SYSTEM LEAVING THE PROVINCE.

-COLUMN 2 IS THE TOTAL EXPORTS SOUTH FROM ALBERTA - ALBERTA AND SOUTHERN, WESTCOAST GL-4 AND PAN-ALBERTA WEST VIA KINGSGATE, BRITISH COLUMBIA; CANADIAN-MONTANA VIA CARDSTON AND ADEN, ALBERTA; AND PAN-ALBERTA EAST VIA MONCHY, SASKATCHEWAN. COLUMN 2 INCLUDES INCREMENTAL FUEL FOR NEW EXPORTS SOUTH FROM ALBERTA.

-COLUMN 4 IS THE TOTAL REPROCESSING SHRINKAGE FROM COLUMN 5, TABLE G-3.

-COLUMNS 5, 7 AND 8 ARE THE CANADIAN REQUIREMENTS EXCLUDING ALBERTA. THEY INCLUDE FUEL AND LOSSES ASSOCIATED WITH TRANSMISSION AND DISTRIBUTION OUTSIDE ALBERTA BUT DO NOT INCLUDE INCREMENTAL FUEL FOR NEW EXPORTS.

-COLUMN 6 IS THE WESTCOAST GL-41 EXISTING EXPORTS PLUS THE NEW COLUMBIA EXPORTS INCLUDING INCREMENTAL FUEL FOR THE NEW EXPORTS.

-COLUMN 9 IS THE TOTAL EXPORTS EAST OF ALBERTA - TCPL INCLUDING GL-1 EXTENSION, ICG TRANSMISSION LIMITED, NIAGARA GL-6 AND NEW, SULPETRO, CONSOLIDATED, AND PROGAS. COLUMN 9 INCLUDES INCREMENTAL FUEL FOR NEW EXPORTS EAST OF ALBERTA.

-THE EXISTING EXPORTS IN COLUMNS 2, 6 AND 9 HAVE BEEN GIVEN THE FULL PROTECTION DESCRIBED IN CHAPTER 8.

REPROCESSING SHRINKAGES

(PETAJOULES/YEAR)

YEAR	(1) COCHRANE	(2) EMPRESS	(3) EDMONION	(4) WATERION	(5) TOTAL (1+2+3+4)
1980	57	110	29	12	207
1981	57	110	29	12	207
1982	57	110	32	12	210
1983	57	110	32	12	210
1984	57	110	32	12	210
1985	57	111	33	12	212
1986	57	139	33	11	239
1987	57	139	31	10	236
1988	57	139	27	8	232
1989	57	139	16	7	219
1990	57	139	17	5	218
1991	57	139	18	4	218
1992	57	139	26	4	227
1993	57	139	27	4	228
1994	57	139	28	3	228
1995	57	139	30	3	229
1996	57	139	32	3	231
1997	57	139	32	3	231
1998	57	139	33	2	231
1999	57	139	33	2	231
2000	57	139	34	2	232
TOTAL	1195	2747	600	142	4684

-COLUMNS 1 TO 4 ARE THE FORECAST OF REPROCESSING SHRINKAGE AS PRESENTED IN THE 1979 GAS REPORT.

CANADIAN GAS DELIVERABILITY FROM CONTROLLED RESERVES

(PETAJOULES/YEAR)

YEAR	(1) TCPL	(2) A+S	(3) WTCL GL-4	(4) WTCL GL-4	(5) PAN ALTA	(6) SULPETRO SUPPLY	(7) PROGAS SUPPLY	(8) COLUMB SUPPLY	(9) PAN ALTA NEW GAS	(10) ALTA UTIL	(11) CAN MONTANA	(12) MIP	(13) PROD EAST ALTA	(14) TOTAL
REMAINING RESERVES AT 31 DECEMBER 1979	25833	7088	7465	333	1345	70	1434	165	4630	8022	290	650	1630	58955
1980	1543	613	489	50	69	27	20	14	3	377	10	21	56	3292
1981	1654	643	505	42	58	23	81	14	115	370	10	22	54	3591
1982	1709	606	514	35	58	19	108	14	427	358	10	25	53	3938
1983	1763	576	493	30	58	0	115	14	430	345	10	27	52	3914
1984	1833	539	483	25	58	0	115	14	430	321	10	31	49	3908
1985	1860	494	444	15	58	0	111	14	430	289	10	30	44	3799
1986	1760	488	393	5	58	0	101	14	401	264	10	26	48	3568
1987	1614	451	327	5	58	0	91	12	333	236	10	23	51	3212
1988	1436	384	299	5	58	0	82	10	273	223	18	20	44	2853
1989	1255	344	258	5	58	0	75	9	233	203	15	18	40	2513
1990	1125	311	234	5	52	0	67	8	207	188	13	16	37	2261
1991	1008	275	206	5	45	0	60	3	181	175	12	15	33	2017
1992	899	247	179	5	40	0	54	1	159	164	10	13	31	1799
1993	819	221	150	5	35	0	43	1	140	171	9	12	29	1633
1994	744	196	129	5	31	0	34	1	120	164	8	11	24	1465
1995	645	174	107	5	26	0	29	1	107	152	7	10	24	1286
1996	580	138	114	5	23	0	25	0	94	134	7	8	22	1150
1997	518	118	106	4	20	0	23	0	84	175	6	7	21	1083
1998	459	102	97	1	18	0	21	0	75	164	5	6	20	967
1999	406	89	85	1	16	0	13	0	55	155	5	6	19	850
2000	359	78	74	1	14	0	12	0	48	140	4	5	18	753
TOTAL	23988	7087	5686	258	910	70	1278	146	4345	4764	201	352	767	49853

-NEW FORECASTS OF PRODUCTION FROM CONTRACTED RESERVES FOR TCPL (INCLUDING CONSOLIDATED), A+S, WESTCOAST GL-41, WESTCOAST GL-4, SULPETRO, PROGAS, COLUMBIA, PAN-ALBERTA (NEW PERMIT FIELDS) AND CANADIAN-MONTANA ARE IN COLUMNS 1, 2, 3, 4, 6, 7, 8, 9 AND 11 RESPECTIVELY. THE PAN-ALBERTA FORECAST (COLUMN 9) INCLUDES THE SULPETRO SUPPLY CAPABILITY AFTER 1982 AND EXCLUDES SUPPLY FROM A+S IN THE YEARS 1980 TO 1982.

-THE WESTCOAST GL-41 FORECAST INCLUDES ALL GAS IN THE WESTCOAST SUPPLY AREA EXCEPTING 0.2 EJ OF BRITISH COLUMBIA RESERVES BEYOND ECONOMIC REACH AND 0.5 EJ OF UNCOMMITTED RESERVES (I.E. THE 1979 RESERVES ADDITION).

-COLUMN 5 IS THE FORECAST OF PAN-ALBERTA'S AERCB PERMIT NO. PA 74-1 SUPPLY ADOPTED FROM PAN-ALBERTA.

-COLUMN 10 IS THE FORECAST OF ALBERTA UTILITIES SUPPLY ADOPTED FROM THE INTERNATIONAL ENERGY CONSULTANT'S FORECAST FOR THE JOINT APPLICANTS.

-COLUMN 12 IS THE FORECAST OF MANY ISLANDS PIPELINES' SUPPLY ADOPTED FROM THE SFC SUBMISSION AT THE 1978 GAS INQUIRY.

-COLUMN 13, PRODUCTION EAST OF ALBERTA, INCLUDES THE FORECAST OF SASKATCHEWAN PRODUCTION FROM THE SFC SUBMISSION AT THE 1978 GAS INQUIRY AND THE BOARD'S FORECAST OF ONTARIO PRODUCTION.

-REMAINING RESERVES AT 31 DECEMBER 1979 REPRESENT THE BOARD'S ESTIMATES BASED UPON AVAILABLE INFORMATION REGARDING CONTROLLED SUPPLIES. THE RESERVES FOR PAN-ALBERTA (COLUMN 9) INCLUDE ALL SULPETRO QUANTITIES NOT

TABLE G-5

GAS SUPPLY AVAILABLE TO MEET ALBERTA DEMAND

(PETAJOULES/YEAR)

YEAR	(1) TOTAL DEMAND	(2) ALBERTA SUPPLIES	(3) TCPL ALTA SUPPLIES	(4) DEFERRED SUPPLY	(5) UNCOMMITTED SUPPLY	(6) SUPPLY FROM RESERVES	(7) ALBERTA TREND	(8) TOTAL (2+3+4+5+6+7)	(9) SURPLUS (8-1)
1980	1325	1073	164	0	85	3	0	1325	0
1981	1483	1201	148	0	170	5	0	1524	40
1982	1771	1452	148	0	255	8	0	1864	92
1983	1797	1411	148	0	341	11	0	1910	113
1984	1793	1350	148	0	426	14	0	1938	145
1985	1683	1272	148	0	482	16	0	1917	235
1986	1506	1202	148	0	510	19	0	1879	373
1987	1228	1069	148	0	525	21	0	1763	534
1988	1089	934	148	0	534	23	0	1639	550
1989	1011	832	148	0	528	25	0	1533	522
1990	994	758	140	0	512	27	0	1438	444
1991	995	673	128	0	487	30	0	1318	323
1992	977	603	116	0	454	31	0	1204	227
1993	998	559	108	0	418	32	0	1116	118
1994	969	502	100	0	382	34	0	1017	48
1995	984	449	89	0	348	35	0	921	-63
1996	995	378	82	10	315	36	0	821	-173
1997	1004	385	76	20	285	37	0	802	-202
1998	1014	341	69	30	257	37	0	734	-280
1999	1022	297	64	40	231	38	0	670	-352
2000	1032	263	59	50	211	38	0	620	-411
TOTAL	25672	17004	2525	149	7755	519	0	27952	2280

-COLUMN 1 IS THE TOTAL ALBERTA DEMAND INCLUDING EXPORTS SOUTH FROM ALBERTA AND IS THE SUM OF COLUMNS 1 TO 4 ON TABLE G-2.

-COLUMN 2 IS THE SUM OF THE ALBERTA UTILITIES FORECAST, THE A+S FORECAST LESS A+S COLUMBIA SALES, THE WESTCOAST GL-4 FORECAST INCLUDING PAN-ALBERTA (FA 74-1) SALES TO WESTCOAST GL-4, THE CANADIAN-MONTANA FORECAST, THE PAN-ALBERTA (NEW PERMIT) FORECAST, THE PAN-ALBERTA (FA 74-1) SALES IN ALBERTA AND THE WESTCOAST GL-41 ALBERTA SUPPLY AFTER 1989.

-COLUMN 3 IS THE BOARD'S ESTIMATE OF TCPL'S ALBERTA SALES AND THE AGTL FUEL AND REPROCESSING SHRINKAGES ASSOCIATED WITH TCPL'S SUPPLY (COLUMNS 3 AND 4, TABLE G-7).

-COLUMN 4 IS THE BOARD'S ESTIMATE OF SUPPLY FROM DEFERRED RESERVES IN ALBERTA.

-COLUMN 5 IS THE BOARD'S ESTIMATE OF SUPPLY FROM UNCOMMITTED GAS RESERVES IN ALBERTA.

-COLUMN 6 IS THE BOARD'S ESTIMATE OF SUPPLY FROM 1/2 OF THE RESERVES BEYOND ECONOMIC REACH IN ALBERTA AND INCLUDES SUPPLY FROM 0.1 EJ OF RESERVES BEYOND ECONOMIC REACH IN BRITISH COLUMBIA.

-COLUMN 7 DOES NOT INCLUDE A FORECAST OF SUPPLY FROM ALBERTA FUTURE RESERVES ADDITIONS SINCE THIS CURRENT DELIVERABILITY TEST DOES NOT INCLUDE RESERVES ADDITIONS.

-COLUMN 9 IS THE QUANTITY OF GAS SUPPLY IN EXCESS OF ALBERTA'S TOTAL REQUIREMENTS.

TABLE G-6

ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND

(PETAJOULES/YEAR)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
YEAR	TOTAL DEMAND	WESTCOAST SUPPLY	PAN ALTA SUPPLY	COLUMBIA SUPPLY	A+S SALES COLUMBIA	UNCOMMITTED BC SUPPLY	BC TREND	NET BC SUPPLY (2+3+4+5+6+7)	DEMAND FOR ALTA GAS (1-8)
1980	538	489	29	14	5	4	0	542	-4
1981	547	505	16	14	6	8	0	550	-3
1982	557	514	20	14	7	13	0	569	-12
1983	568	493	15	14	8	17	0	548	21
1984	584	483	10	14	8	21	0	537	47
1985	594	444	0	14	10	23	0	491	103
1986	595	393	0	14	10	24	0	441	154
1987	595	327	0	12	11	25	0	375	220
1988	598	299	0	10	12	25	0	347	251
1989	548	258	0	9	12	25	0	304	244
1990	271	224	0	8	12	24	0	268	3
1991	280	198	0	3	13	23	0	237	43
1992	291	172	0	1	13	22	0	208	84
1993	303	144	0	1	13	20	0	177	126
1994	315	123	0	1	13	19	0	155	160
1995	329	102	0	1	13	17	0	132	197
1996	342	108	0	0	13	15	0	136	206
1997	356	101	0	0	13	14	0	128	228
1998	372	93	0	0	13	13	0	119	253
1999	388	81	0	0	13	12	0	105	283
2000	405	70	0	0	13	11	0	93	312
TOTAL	9375	5622	89	146	227	375	0	6460	2915

-COLUMN 1 IS THE TOTAL BRITISH COLUMBIA DEMAND OBTAINED BY ADDING THE TOTAL DOMESTIC AND EXPORT DEMANDS, COLUMNS 5 AND 6 FROM TABLE G-2.

-COLUMN 2 IS THE NEW FORECAST OF WESTCOAST GL-41 GAS SUPPLY FROM COLUMN 3, TABLE F-4 AND EXCLUDES THE QUANTITIES FROM ITS ALBERTA PERMIT FIELDS AFTER THE PERMITS EXPIRE IN 1989.

-COLUMN 3 IS THE BOARD'S ESTIMATE OF THE PAN-ALBERTA (PA 74-1 PERMIT) SALES TO WESTCOAST FOR WESTCOAST'S GL-41 EXPORTS.

-COLUMN 4 IS THE BOARD'S FORECAST OF COLUMBIA'S KOTANEELEE SUPPLY FROM COLUMN 8, TABLE G-4.

-COLUMN 5 IS A+S'S ESTIMATE OF ITS SALES TO COLUMBIA NATURAL GAS IN BRITISH COLUMBIA.

-COLUMN 6 IS THE BOARD'S FORECAST OF SUPPLY FROM UNCOMMITTED RESERVES (I.E. THE 1979 RESERVES ADDITION) IN BRITISH COLUMBIA.

-COLUMN 7 DOES NOT INCLUDE A FORECAST OF SUPPLY FROM BRITISH COLUMBIA FUTURE RESERVES ADDITIONS SINCE THIS CURRENT DELIVERABILITY TEST DOES NOT INCLUDE RESERVES ADDITIONS.

-COLUMN 9 IS THE ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND.

(PETAJOULES/YEAR)

YEAR	(1) TOTAL DEMAND	(2) TCPL SUPPLY	(3) TCPL ALTA SALES	(4) AGTL FUEL	(5) MIF SUPPLY	(6) SULPETRO SUPPLY	(7) PROGAS SUPPLY	(8) FAN ALTA SUPPLY	(9) PROD EAST ALTA	(10) SASK TREND	(11) NET SUPPLY (2-3-4+5+6 +7+8+9+10)	(12) DEMAND FOR ALTA GAS (1-11)
1980	1517	1543	38	127	21	27	20	15	56	0	1517	0
1981	1736	1654	21	127	22	23	81	15	54	0	1701	35
1982	1792	1709	21	127	25	19	108	15	53	0	1782	10
1983	1827	1763	21	127	27	0	115	15	52	0	1825	3
1984	1890	1833	21	127	31	0	115	15	49	0	1894	-4
1985	1878	1860	21	127	30	0	111	15	44	0	1911	-33
1986	1811	1760	21	127	26	0	101	15	48	0	1802	9
1987	1802	1614	21	127	23	0	91	15	51	0	1646	156
1988	1801	1436	21	127	20	0	82	15	44	0	1449	351
1989	1838	1255	21	127	18	0	75	15	40	0	1255	583
1990	1822	1125	21	119	16	0	67	15	37	0	1119	703
1991	1772	1008	21	107	15	0	60	15	33	0	1003	769
1992	1781	899	21	95	13	0	54	15	31	0	894	887
1993	1840	819	21	87	12	0	43	15	29	0	809	1031
1994	1906	744	21	79	11	0	34	15	24	0	727	1178
1995	1974	645	21	68	10	0	29	15	24	0	634	1341
1996	2030	580	21	61	8	0	25	15	22	0	568	1462
1997	2103	518	21	55	7	0	23	15	21	0	508	1595
1998	2183	459	21	48	6	0	21	15	20	0	451	1732
1999	2265	406	21	43	6	0	13	15	19	0	395	1869
2000	2353	359	21	38	5	0	12	14	18	0	349	2004
TOTAL	39921	23988	460	2065	352	70	1278	310	767	0	24240	15682

-COLUMN 1 IS THE TOTAL DEMAND FOR GAS EAST OF ALBERTA FROM COLUMNS 7, 8 AND 9, TABLE G-2.

-COLUMN 2 IS THE NEW FORECAST OF SUPPLY FROM TCPL'S CONTRACTED GAS QUANTITIES (COLUMN 1, TABLE G-4).

-COLUMN 3 IS THE BOARD'S ESTIMATE OF TCPL'S SALES TO ALBERTA UTILITIES.

-COLUMN 4 IS THE NEW ESTIMATE OF EMPRESS SHRINKAGE AND AGTL FUEL REQUIRED TO TRANSPORT GAS FOR EAST OF ALBERTA USE. THE VOLUMES ARE BASED ON TCPL THROUGHPUT.

-COLUMN 5 IS THE MANY ISLANDS PIPELINES' FORECAST OF PRODUCTION FROM COLUMN 12, TABLE G-4.

-COLUMN 6 IS THE NEW FORECAST OF SULPETRO GAS SUPPLY, FROM COLUMN 6, TABLE G-4, TO MEET ITS GRANTED EXPORT QUANTITIES.

-COLUMN 7 IS THE NEW FORECAST OF PROGAS GAS SUPPLY FROM COLUMN 7, TABLE G-4.

-COLUMN 8 IS THE FAN-ALBERTA ESTIMATE OF ITS SALES TO GAS METRO FROM ITS AERCB FA 74-1 PERMIT FIELDS.

-COLUMN 9 IS THE FORECAST OF PRODUCTION EAST OF ALBERTA (COLUMN 13, TABLE G-4).

-COLUMN 10 DOES NOT INCLUDE A FORECAST OF SUPPLY FROM SASKATCHEWAN FUTURE RESERVES ADDITIONS SINCE THIS CURRENT DELIVERABILITY TEST DOES NOT INCLUDE RESERVES ADDITIONS.

-COLUMN 12 IS THE ADDITIONAL GAS SUPPLY NECESSARY TO MEET TOTAL DEMAND EAST OF ALBERTA.

TABLE G-8

ALLOCATION OF GAS SURPLUS TO ALBERTA DEMAND

(PETAJOULES/YEAR)

YEAR	SURPLUS SUPPLIES		(3)	DEMAND FOR ALTA SURPLUS		ALLOCATION OF SURPLUS		(8)
	(1)	(2)		(4)	(5)	(6)	(7)	
	ALBERTA SURPLUS	SUPPLY FROM TEMP SURPLUS	TOTAL	EAST OF ALBERTA	BRITISH COLUMBIA	EAST OF ALBERTA	BRITISH COLUMBIA	TEMP SURPLUS FOR LATER
1980	0	0	4	0	-4	0	0	4
1981	40	0	43	35	-3	35	0	8
1982	92	0	104	10	-12	10	0	94
1983	113	0	113	3	21	3	21	89
1984	145	0	148	-4	47	0	47	101
1985	235	0	268	-33	103	0	103	165
1986	373	0	373	9	154	9	154	210
1987	534	0	534	156	220	156	220	158
1988	550	43	593	351	251	346	247	0
1989	522	43	566	583	244	398	167	0
1990	444	43	487	703	3	485	2	0
1991	323	43	366	769	43	347	19	0
1992	227	43	270	887	84	246	23	0
1993	118	43	161	1031	126	144	18	0
1994	48	43	91	1178	160	80	11	0
1995	-63	42	-21	1341	197	-19	-3	0
1996	-173	39	-135	1462	206	-118	-17	0
1997	-202	35	-167	1595	228	-146	-21	0
1998	-280	32	-248	1732	253	-216	-32	0
1999	-352	28	-324	1869	283	-281	-43	0
2000	-411	26	-386	2004	312	-334	-52	0
TOTAL	2280	504	2839	15682	2915	1145	865	830

-COLUMN 1 IS THE TOTAL PROJECTED SUPPLY OF GAS SURPLUS TO ALBERTA'S REQUIREMENTS FROM COLUMN 9, TABLE G-5.

-GAS WAS ASSUMED TO FLOW EITHER EAST OR WEST TO MEET DEFICIENCIES AS REQUIRED.

-AFTER SUPPLYING BRITISH COLUMBIA AND EAST OF ALBERTA AS SHOWN IN COLUMNS 6 AND 7, THERE REMAIN QUANTITIES OF GAS WHICH PROVIDE A TEMPORARY OVERALL SURPLUS TO TOTAL DEMAND. THESE QUANTITIES, SHOWN IN COLUMN 8, ARE ASSUMED NOT TO BE PRODUCED AND ARE CONVERTED TO A FORECAST OF DELIVERABILITY STARTING IN 1988 AS SHOWN IN COLUMN 2. THEY ARE PRODUCED AT A RATE OF 1:7000 UNTIL 40 PERCENT DEPLETION AND DECLINED AT 10 PERCENT PER YEAR THEREAFTER.

-THE TOTAL SURPLUS SUPPLY, COLUMN 3, IS ALLOCATED BETWEEN BRITISH COLUMBIA AND EAST OF ALBERTA BASED UPON THE PROPORTION THE UNSATISFIED DEMAND WHICH IS ATTRIBUTABLE TO EACH OF THESE REGIONS.

ADJUSTMENTS TO ALBERTA UNCOMMITTED AND TREND SUPPLIES

(PETAJOULES/YEAR)

YEAR	(1) TEMPORARY SURPLUS SUPPLY	(2) DEFERRED DELIVERABILITY	UNADJUSTED		ADJUSTED	
			(3) ALBERTA UNCOMMITTED	(4) ALBERTA TREND	(5) ALBERTA UNCOMMITTED	(6) ALBERTA TREND
1980	4	0	89	0	85	0
1981	8	0	175	0	167	0
1982	94	0	264	0	169	0
1983	89	0	351	0	262	0
1984	101	0	440	0	338	0
1985	165	0	498	0	333	0
1986	210	0	529	0	319	0
1987	158	0	546	0	389	0
1988	0	43	557	0	600	0
1989	0	43	554	0	597	0
1990	0	43	539	0	582	0
1991	0	43	517	0	560	0
1992	0	43	484	0	527	0
1993	0	43	449	0	492	0
1994	0	43	416	0	459	0
1995	0	42	383	0	425	0
1996	0	39	351	0	390	0
1997	0	35	322	0	357	0
1998	0	32	294	0	326	0
1999	0	28	269	0	297	0
2000	0	26	249	0	274	0
TOTAL	830	504	8274	0	7948	0

-COLUMN 1 IS THE TEMPORARY SURPLUS ALBERTA SUPPLY TAKEN FROM COLUMN 8, TABLE G-8.

-COLUMN 2 IS THE DELIVERABILITY, STARTING IN 1988, ATTRIBUTABLE TO THE QUANTITIES INDICATED TO BE SURPLUS IN COLUMN 1 AND ASSUMED NOT TO BE PRODUCED IN THE PERIOD INDICATED IN COLUMN 1.

-THE FIGURES IN COLUMNS 1 AND 2 WERE USED TO ADJUST THE NEB FORECAST OF SUPPLY FROM UNCOMMITTED ALBERTA GAS, COLUMN 3, WHICH IS THE SUM OF COLUMNS 5 AND 6, TABLE G-5.

-NO ADJUSTMENTS WERE REQUIRED FOR TREND GAS AS THIS CURRENT DELIVERABILITY TEST DOES NOT CONSIDER FUTURE RESERVES ADDITIONS.

-THE ADJUSTED FORECAST OF UNCOMMITTED ALBERTA RESERVES IS SHOWN IN COLUMN 5.

TABLE G-10

BRITISH COLUMBIA SUPPLY/DEMAND BALANCE

(PETAJOULES/YEAR)

YEAR	DEMAND			SUPPLY			DEFICIENCY (3-6)
	(1) B.C. DEMAND	(2) HUNTINGTON EXPORT	(3) TOTAL	(4) B.C. NET SUPPLY	(5) ALTA SURPLUS TO B.C.	(6) TOTAL (4+5)	
1980	196	342	538	542	0	542	-4
1981	206	341	547	550	0	550	-3
1982	216	341	557	569	0	569	-12
1983	228	341	568	548	21	568	0
1984	242	342	584	537	47	584	0
1985	257	337	594	491	103	594	0
1986	262	333	595	441	154	595	0
1987	266	330	595	375	220	595	0
1988	271	327	598	347	247	594	4
1989	277	271	548	304	167	471	77
1990	271	0	271	268	2	270	1
1991	280	0	280	237	19	256	24
1992	291	0	291	208	23	231	61
1993	303	0	303	177	18	195	109
1994	315	0	315	155	11	166	149
1995	329	0	329	132	-3	129	200
1996	342	0	342	136	-17	120	222
1997	356	0	356	128	-21	107	249
1998	372	0	372	119	-32	87	285
1999	388	0	388	105	-43	63	325
2000	405	0	405	93	-52	41	364
TOTAL	6072	3304	9375	6460	865	7326	2050

-COLUMN 1 IS TAKEN FROM COLUMN 5, TABLE G-2.

-COLUMN 2 IS TAKEN FROM COLUMN 6, TABLE G-2.

-COLUMN 4 IS TAKEN FROM COLUMN 8, TABLE G-6.

-COLUMN 5 IS TAKEN FROM COLUMN 7, TABLE G-8.

EAST OF ALBERTA SUPPLY/DEMAND BALANCE

(PETAJOULES/YEAR)

YEAR	DEMAND			SUPPLY			DEFICIENCY (3-6)
	(1) CANADIAN	(2) EXPORT	(3) TOTAL	(4) NET SUPPLY EAST OF ALTA	(5) ALTA SURPLUS TO EAST OF ALTA	(6) TOTAL (4+5)	
1980	1124	393	1517	1517	0	1517	0
1981	1168	568	1736	1701	35	1736	0
1982	1228	563	1792	1782	10	1792	0
1983	1285	542	1827	1825	3	1827	0
1984	1357	534	1890	1894	0	1894	-4
1985	1429	450	1878	1911	0	1911	-33
1986	1474	337	1811	1802	9	1811	0
1987	1522	281	1802	1646	156	1802	0
1988	1566	235	1801	1449	346	1795	5
1989	1616	221	1838	1255	398	1653	184
1990	1671	151	1822	1119	485	1604	218
1991	1712	60	1772	1003	347	1349	423
1992	1768	14	1781	894	246	1141	641
1993	1826	14	1840	809	144	953	887
1994	1892	14	1906	727	80	807	1098
1995	1963	12	1974	634	-19	615	1359
1996	2030	0	2030	568	-118	450	1580
1997	2103	0	2103	508	-146	362	1741
1998	2183	0	2183	451	-216	234	1948
1999	2265	0	2265	395	-281	114	2151
2000	2353	0	2353	349	-334	15	2338
TOTAL	35535	4386	39921	24240	1145	25384	14537

-COLUMN 1 IS TAKEN FROM COLUMNS 7 AND 8, TABLE G-2.

-COLUMN 2 IS TAKEN FROM COLUMN 9, TABLE G-2.

-COLUMN 4 IS TAKEN FROM COLUMN 11, TABLE G-7.

-COLUMN 5 IS TAKEN FROM COLUMN 6, TABLE G-8.

TABLE G-12

TOTAL CANADIAN SUPPLY/DEMAND BALANCE
(PETAJOULES/YEAR)

YEAR	DEMAND			SUPPLY						TOTAL	DEFICIENCY (3-9)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)		
	DOMESTIC	EXPORT	TOTAL	TOTAL CONTROLLED	ALBERTA UNCOMMITTED	B C UNCOMMITTED	ALTA DEFERRED	TREND SUPPLY	(4+5+6+7+8)		
REMAINING RESERVES AT 31 DECEMBER 1979				58955	13423	530	2858	0	75766		
1980	2067	1314	3361	3292	85	4	0	0	3381	0	0
1981	2143	1624	3767	3591	167	8	0	0	3767	0	0
1982	2229	1891	4120	3938	169	13	0	0	4120	0	0
1983	2323	1870	4193	3914	262	17	0	0	4193	0	0
1984	2424	1843	4267	3908	338	21	0	0	4267	0	0
1985	2534	1621	4155	3799	333	23	0	0	4155	0	0
1986	2603	1309	3912	3568	319	24	0	0	3912	0	0
1987	2661	965	3626	3212	389	25	0	0	3626	0	0
1988	2731	756	3488	2853	600	25	0	0	3478	9	9
1989	2784	612	3397	2513	597	25	0	0	3135	262	262
1990	2841	246	3087	2261	582	24	0	0	2868	219	219
1991	2900	147	3046	2017	560	23	0	0	2600	446	446
1992	2987	63	3050	1799	527	22	0	0	2349	701	701
1993	3087	55	3141	1633	492	20	0	0	2145	996	996
1994	3176	14	3190	1465	459	19	0	0	1943	1247	1247
1995	3275	12	3287	1286	425	17	0	0	1728	1559	1559
1996	3367	0	3367	1150	390	15	10	0	1565	1802	1802
1997	3464	0	3464	1083	357	14	20	0	1473	1990	1990
1998	3568	0	3568	967	326	13	30	0	1335	2233	2233
1999	3675	0	3675	850	297	12	40	0	1199	2476	2476
2000	3789	0	3789	753	274	11	50	0	1088	2702	2702
TOTAL	60629	14339	74968	49853	7948	375	149	0	58326	16642	16642

—FIGURES MAY NOT ADD DUE TO ROUNDING.

—BOARD ESTIMATES OF THE REMAINING MARKETABLE RESERVES AT 31 DECEMBER, 1979 WHICH SUPPORT THE NEB FORECASTS OF SUPPLY ARE SHOWN AT THE TOP OF COLUMNS 4 TO 9.

—COLUMN 5 INCLUDES THE UNCOMMITTED ALBERTA RESERVES AT 31 DECEMBER, 1978, THE TOTAL RESERVES BEYOND ECONOMIC REACH IN ALBERTA AND BRITISH COLUMBIA, AND THE 1979 ALBERTA RESERVES ADDITION.

—COLUMN 6 IS THE SUPPLY FORECAST FROM THE 1979 RESERVES ADDITION IN BRITISH COLUMBIA.

—COLUMNS 1 TO 7 INCLUSIVE ARE TAKEN FROM COLUMNS 10, 11 AND 12, TABLE G-2; COLUMN 14, TABLE G-4; COLUMN 5, TABLE G-9; COLUMN 6, TABLE G-6 AND COLUMN 4, TABLE G-5.

—THE TOTAL DEFICIENCY IN COLUMN 10 INCLUDES THE POSITIVE DEFICIENCIES FOR BRITISH COLUMBIA AND EAST OF ALBERTA FROM COLUMN 7, TABLE G-10 AND COLUMN 7, TABLE G-11 RESPECTIVELY.

FORM OF THE PROPOSED
LICENCES AND AMENDING ORDERS

In accordance with decisions reached earlier in this Report, the Board therefore will, subject to the approval of the Governor in Council, issue the following licences and orders and containing the respective terms and conditions indicated:

To Alberta and Southern Gas Co. Ltd.

A. An order amending Licence No. GL-3 by

- (1) revoking conditions 1 and 2 therefrom and substituting therefor the following:

"1. the term of this licence shall commence on the 31st day of October, 1961, and end on the 31st day of October, 1987;

2. the quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:

(a) for the period commencing on the 31st day of October, 1961, and ending on the 30th day of October, 1986, 12 995 400 cubic metres in any one day, or the quantity which shall produce an average of 4 341 808 000 cubic metres per year calculated cumulatively on the 31st day of October in each successive year always commencing with the year ending on the 31st day of October, 1962, or 108 382 315 800 cubic metres in the period;

(b) for the period commencing on the 31st day of October, 1986, and ending on the 31st day of October, 1987, 3 248 900 cubic metres in any one day, or 1 085 500 000 cubic metres in the period, or

(c) 109 467 815 800 cubic metres during the term of this licence;"

- (2) adding thereto, immediately after condition 7 a new condition

"8. notwithstanding the limitations in the quantity of gas that may be exported in any one day, and for the purpose only of alleviating temporary operating problems caused by pipeline or equipment failure, the quantity of gas that may be exported in any one day shall be 110 percent of the quantity of gas that may otherwise be exported in any one day,"

B. An order amending Licence No. GL-35 by

- (1) revoking conditions 1 and 2 therefrom and substituting therefor the following:

"1. the term of this licence shall commence on the 1st day of November, 1970, and end on the 31st day of October, 1987;

2. the quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:

(a) for the period commencing on the 1st day of November, 1970, and ending on the 31st day of October, 1985, 5 807 200 cubic metres in any one day, or the quantity which shall produce an average of 1 912 129 200 cubic metres per year calculated cumulatively on the 31st day of October in each successive year commencing with the year ending on the 31st day of October, 1971, or 28 681 938 000 cubic metres in the period;

(b) for the period commencing on the 1st day of November, 1985, and ending on the 31st day of October, 1986, 2 903 600 cubic metres in any one day, or 956 100 000 cubic metres in the period;

(c) for the period commencing on the 1st day of November, 1986, and ending on the 31st day of October, 1987, 1 451 800 cubic metres in any one day, or 478 100 000 cubic metres in the period, or

(d) 30 116 138 000 cubic metres during the term of this licence;"

- (2) adding thereto, immediately after condition 6 a new condition

"7. notwithstanding the limitations in the quantity of gas that may be exported in any one day, and for the purpose only of alleviating temporary operating problems caused by pipeline or equipment failure, the quantity of gas that may be exported in any one day shall be 110 percent of the quantity of gas that may otherwise be exported in any one day,"

To Canadian-Montana Pipe Line Company

- A. A licence for the exportation of gas at a point near Aden, Alberta with the following terms and conditions:
1. The term of this licence shall commence on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and end on the 31st day of December, 1987.
 2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - a) for the period commencing on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and ending on the 31st day of December, 1980, 1 416 400 cubic metres in any one day, or 283 300 000 cubic metres in the period;
 - b) for the period commencing on the 1st day of January, 1981, and ending on the 31st day of December, 1984, 1 416 400 cubic metres in any one day, or 283 300 000 cubic metres in any consecutive twelve-month period ending on the 31st day of December;
 - c) for the period commencing on the 1st day of January, 1985, and ending on the 31st day of December, 1985, 1 062 300 cubic metres in any one day, or 212 500 000 cubic metres in the period;
 - d) for the period commencing on the 1st day of January, 1986, and ending on the 31st day of December, 1986, 708 200 cubic metres in any one day, or 141 600 000 cubic metres in the period;

- (e) for the period commencing on the 1st day of January, 1987, and ending on the 31st day of December, 1987, 354 100 cubic metres in any one day, or 70 800 000 cubic metres in the period, or
 - (f) 1 841 400 000 cubic metres during the term of this licence.
- 3.(1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.
- (2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.
4. Gas exported under the authority of and in accordance with this licence shall be exported at a place on the international boundary line between Canada and the United States of America near Aden in the Province of Alberta.
5. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
6. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

B. A licence for the exportation of gas at a point near Cardston, Alberta with the following terms and conditions:

1. The term of this licence shall commence on the 1st day of July, 1986, and end on the 31st day of October, 1987.
2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - a) for the period commencing on the 1st day of July, 1986, and ending on the 31st day of October, 1986, 339 950 cubic metres in any one day, or 34 500 000 cubic metres in the period;
 - b) for the period commencing on the 1st day of November, 1986, and ending on the 31st day of October, 1987, 169 975 cubic metres in any one day, or 51 700 000 cubic metres in the period, or
 - c) 86 200 000 cubic metres during the term of this licence.
3. Notwithstanding condition 2, the total quantity of gas that may be exported under the authority of and in accordance with this licence together with the quantity of gas that may be exported under the authority of and in accordance with Licence GL-25 shall not exceed 206 800 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October.
4. (1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.
 - (2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which

rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.

5. Gas exported under the authority of and in accordance with this licence shall be exported at a place on the international boundary line between Canada and the United States of America near Cardston in the Province of Alberta.
6. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
7. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

C. An order amending Licence No. GL-5 by revoking conditions 1, 2, 7 and 8 therefrom, and substituting therefor the following:

- "1. the term of this licence shall commence on the 31st day of October, 1961, and end on the 31st day of October, 1987;
2. the quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - a) for the period commencing on the 31st day of October, 1961, and ending on the 30th day of October, 1986, 1 019 800 cubic metres in any one day, or the quantity which shall produce an average of 310 189 800 cubic metres per year calculated cumulatively on the 31st day of October in each successive year always commencing with the year ending on the 31st day of October, 1962, or 7 754 746 200 cubic metres in the period;

- b) for the period commencing on the 31st day of October, 1986, and ending on the 31st day of October, 1987, 255 000 cubic metres in any one day, or 77 600 000 cubic metres in the period, or
- c) 7 832 346 200 cubic metres during the term of this licence;"

D. An order amending Licence No. GL-17 by revoking conditions 5 and 6 therefrom.

E. An order amending Licence No. GL-25 by revoking condition 6 therefrom.

F. An order amending Licence No. GL-36 by revoking conditions 1, 2 and 6 therefrom and substituting therefor the following:

"1. the term of this licence shall commence on the 1st day of November, 1970, and end on the 31st day of October, 1987;

2. the quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:

- a) for the period commencing on the 1st day of November, 1970, and ending on the 31st day of October, 1985, 339 900 cubic metres in any one day, or the quantity which shall produce an average of 103 396 600 cubic metres per year calculated cumulatively on the 31st day of October in each successive year always commencing with the year ending on the 31st day of October, 1971, or 1 550 949 200 cubic metres in the period;

- b) for the period commencing on the 1st day of November, 1985, and ending on the 31st day of October, 1986, 170,000 cubic metres in any one day, or 51 700 000 cubic metres in the period;

- c) for the period commencing on the 1st day of November, 1986, and ending on the 31st day of October, 1987, 85 000 cubic metres in any one day, or 25 900 000 cubic metres in the period, or,
- d) 1 628 549 200 cubic metres during the term of this licence."

To Columbia Gas Development of Canada Ltd.

A. A licence for the exportation of gas at a point near Huntingdon, British Columbia with the following terms and conditions:

1. The term of this licence shall commence on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and end on the 31st day of December, 1987.
2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - a) for the period commencing on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and ending on the 31st day of December, 1980, 1 110 400 cubic metres in any one day, or 368 300 000 cubic metres in the period;
 - b) for the period commencing on the 1st day of January, 1981, and ending on the 31st day of December, 1984, 1 110 400 cubic metres in any one day, or 368 300 000 cubic metres in any consecutive twelve-month period ending on the 31st day of December;
 - c) for the period commencing on the 1st day of January, 1985, and ending on the 31st day of December, 1985, 832 800 cubic metres in any one day, or 276 200 000 cubic metres in the period;
 - d) for the period commencing on the 1st day of January, 1986, and ending on the 31st day of December, 1986, 555 200 cubic metres in any one day, or 184 200 000 cubic metres in the period;

- e) for the period commencing on the 1st day of January, 1987, and ending on the 31st day of December, 1987, 277 600 cubic metres in any one day, or 92 100 000 cubic metres in the period; or
- f) 2 394 000 000 cubic metres during the term of this licence.

- 3.(1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.
- (2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.
- 4. Gas exported under the authority of and in accordance with this licence shall be exported at a place on the international boundary line between Canada and the United States of America near Huntingdon in the Province of British Columbia.
- 5. Prior to the commencement of the exportation of gas authorized under the authority of and in accordance with this licence, the Licensee shall satisfy the Board that transportation arrangements have been completed and shall file with the Board copies of the necessary executed contracts.
- 6. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
- 7. The Licensee shall, within 15 days of the end of each month comprised in the term of the licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

To Niagara Gas Transmission Limited

A. A licence for the exportation of gas at a point near Cornwall, Ontario with the following terms and conditions:

1. The term of this licence shall commence on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and end on the 31st day of October, 1987.
2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - a) for the period commencing on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and ending on the 31st day of October, 1980, 350 000 cubic metres in any one day, or 89 100 000 cubic metres in the period;
 - b) for the period commencing on the 1st day of November, 1980, and ending on the 31st day of October, 1984, 350 000 cubic metres in any one day, or 89 100 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October;
 - c) for the period commencing on the 1st day of November, 1984, and ending on the 31st day of October, 1985, 262 500 cubic metres in any one day, or 66 800 000 cubic metres in the period;
 - d) for the period commencing on the 1st day of November, 1985, and ending on the 31st day of October, 1986, 600 000 cubic metres in any one day, or 136 800 000 cubic metres in the period;
 - e) for the period commencing on the 1st day of November, 1986, and ending on the 31st day of October, 1987, 300 000 cubic metres in any one day, or 68 400 000 cubic metres in the period;
or
 - f) 717 500 000 cubic metres during the term of this licence.
3. As a tolerance, the amount the Licensee may export under this licence may, in any 24-hour period, exceed the daily limitation imposed in condition 2 by two percent of such amount.

- 4.(1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.
- (2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.
5. Gas exported under the authority of and in accordance with this licence shall be exported at a place on the international boundary line between Canada and the United States of America near Cornwall in the Province of Ontario.
6. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
7. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

To ProGas Limited

- A. A licence for the exportation of gas at a point near Emerson, Manitoba with the following terms and conditions:
1. The term of this licence shall commence on the 1st day of November, 1980, and end on the 31st day of October, 1987.
 2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:

- (a) for the period commencing on the 1st day of November, 1980, and ending on the 31st day of October, 1984, 9 440 900 cubic metres in any one day, or 3 100 000 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October;
 - (b) for the period commencing on the 1st day of November, 1984, and ending on the 31st day of October, 1985, 7 088 700 cubic metres in any one day, or 2 325 000 000 cubic metres in the period;
 - (c) for the period commencing on the 1st day of November, 1985, and ending on the 31st day of October, 1986, 4 720 400 cubic metres in any one day, or 1 550 000 000 cubic metres in the period;
 - (d) for the period commencing on the 1st day of November, 1986, and ending on the 31st day of October, 1987, 2 360 200 cubic metres in any one day, or 775 000 000 cubic metres in the period, or
 - (e) 17 050 000 000 cubic metres during the term of this licence.
3. As a tolerance, the amount the Licensee may export under this licence may, in any 24-hour period, exceed the daily limitation imposed in condition 2 by two percent of such amount.
- 4.(1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.
- (2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.

5. Gas exported under the authority of and in accordance with this licence shall be exported at a place on the international boundary line between Canada and the United States of America near Emerson in the Province of Manitoba.
6. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
7. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

To Sulpetro Limited

- A. A licence for the exportation of gas at a point near Niagara Falls, Ontario with the following terms and conditions:
1. The term of this licence shall commence on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and end on the 31st day of October, 1982.
 2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - a) 2 089 100 cubic metres in any one day;
 - b) for the period commencing on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and ending on the 31st day of October, 1980, 612 800 000 cubic metres in the period;
 - c) for the period commencing on the 1st day of November, 1980, and ending on the 31st day of October, 1982, 612 800 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October, or
 - d) 1 838 400 000 cubic metres during the term of this licence.

- 3.(1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.
- (2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.
4. Gas exported under the authority of and in accordance with this licence shall be exported at a place on the international boundary line between Canada and the United States of America near Niagara Falls in the Province of Ontario.
5. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
6. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

To Westcoast Transmission Company Ltd.

A. An order amending Licence No. GL-4 by revoking conditions 1 and 2 therefrom, and substituting therefor the following:

- "1. the term of this licence shall commence on the 10th day of December, 1961, and end on the 31st day of October, 1987.
2. the quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - (a) for the period commencing on the 10th day of December, 1961, and ending on the 9th day of December, 1981, 4 305 800 cubic metres in any one day, or the quantity which shall produce an average of 1 444 719 800 cubic metres per year calculated cumulatively on the 31st day of October in each successive year always commencing with the year ending on the 31st day of October, 1969, or 28 894 396 800 cubic metres in the period;
 - (b) for the period commencing on the 10th day of December, 1981, and ending on the 31st day of October, 1982, 4 305 800 cubic metres in any one day, or 1 300 000 000 cubic metres in the period;
 - (c) for the period commencing on the 1st day of November, 1982, and ending on the 31st day of October, 1984, 4 305 800 cubic metres in any one day, or 1 444 700 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October;
 - (d) for the period commencing on the 1st day of November, 1984, and ending on the 31st day of October, 1985, 3 229 400 cubic metres in any one day, or 1 083 500 000 cubic metres in the period;
 - (e) for the period commencing on the 1st day of November, 1985 and ending on the 31st day of October, 1986, 2 152 900 cubic metres in any one day, or 722 400 000 cubic metres in the period;

- (f) for the period commencing on the 1st day of November, 1986 and ending on the 31st day of October, 1987, 1 076 500 cubic metres in any one day, or 361 200 000 cubic metres in the period, or
- (g) 35 250 896 800 cubic metres during the term of this licence;"

B. An order amending Licence No. GL-41 by revoking condition 2 therefrom, and substituting therefrom the following:

"2. the quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:

- (a) for the period commencing on the 1st day of November, 1972, and ending on the 31st day of October, 1980, 22 922 900 cubic metres in any one day;
- (b) for the period commencing on the 1st day of November, 1980, and ending on the 31st day of October, 1989, 24 622 570 cubic metres in any one day;
- (c) for the period commencing on the 1st day of November, 1972, and ending on the 31st day of October, 1989, the quantity which shall produce an average of 7 970 288 200 cubic metres per year calculated cumulatively on the 31st day of October in each successive year always commencing with the year ending on the 31st day of October, 1973, or 8 389 800 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October, or
- (d) 142 853 331 200 cubic metres during the term of this licence.

To Pan-Alberta Gas Ltd.

A. A licence for the exportation of gas at a point near Monchy, Saskatchewan with the following terms and conditions:

1. The term of this licence shall commence on the 1st day of November, 1981, and end on the 31st day of October, 1987.
2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - (a) for the period commencing on the 1st day of November, 1981, and ending on the 31st day of October, 1984, 24 928 500 cubic metres in any one day, or 8 294 400 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October;
 - (b) for the period commencing on the 1st day of November, 1984, and ending on the 31st day of October, 1985, 18 696 400 cubic metres in any one day, or 6 220 800 000 cubic metres in the period;
 - (c) for the period commencing on the 1st day of November, 1985, and ending on the 31st day of October, 1986, 12 464 300 cubic metres in any one day, or 4 147 200 000 cubic metres in the period;
 - (d) for the period commencing on the 1st day of November, 1986, and ending on the 31st day of October, 1987, 6 232 100 cubic metres in any one day, or 2 073 600 000 cubic metres in the period, or
 - (e) 37 324 800 000 cubic metres during the term of this licence.

3. As a tolerance, the amount the Licensee may export under this licence may, in any 24-hour period, exceed the daily limitation imposed in condition 2 by two percent of such amount.
- 4.(1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.

(2) The Canadian dollar equivalent for each month comprised in the terms of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.
5. Gas exported under the authority of and in accordance with this licence shall be delivered to the point of export near Monchy, in the Province of Saskatchewan, through the pipeline systems of Foothills Pipe Lines (Alta.) Ltd. and Foothills Pipe Lines (Sask.) Ltd.
6. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
7. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

B. A licence for the exportation of gas at a point near Kingsgate, British Columbia with the following terms and conditions:

1. The term of this licence shall commence on the 1st day of November, 1980, and end on the 31st day of October, 1987.
2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - (a) for the period commencing on the 1st day of November, 1980, and ending on the 31st day of October, 1984, 7 478 600 cubic metres in any one day, or 2 488 300 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October;
 - (b) for the period commencing on the 1st day of November, 1984, and ending on the 31st day of October, 1985, 5 608 900 cubic metres in any one day, or 1 866 200 000 cubic metres in the period,
 - (c) for the period commencing on the 1st day of November, 1985, and ending on the 31st day of October, 1986, 3 739 300 cubic metres in any one day, or 1 244 200 000 cubic metres in the period,
 - (d) for the period commencing on the 1st day of November, 1986, and ending on the 31st day of October, 1987, 1 869 000 cubic metres in any one day, or 622 100 000 cubic metres in the period, or
 - (e) 13 685 700 000 cubic metres during the term of this licence.

3. As a tolerance, the amount the Licensee may export under this licence may, in any 24-hour period, exceed the daily limitation imposed in condition 2 by two percent of such amount.
- 4.(1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.
- (2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each month, as published by the Bank of Canada.
5. Gas exported under the authority of and in accordance with this licence shall be delivered to the point of export near Kingsgate, in the Province of British Columbia, through the pipeline systems of Foothills Pipe Lines (Alta.) Ltd. and Foothills Pipe Lines (South B.C.) Ltd.
6. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
7. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

To TransCanada PipeLines Limited

A. A licence for the exportation of gas at a point near Emerson, Manitoba with the following terms and conditions:

1. The term of this licence shall commence on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and end on the 14th day of December, 1985.
2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:

- a) for the period commencing on the 1st day of January, 1980, or on the date this licence is approved by Governor in Council, whichever is the later date, and ending on the 31st day of October, 1980, 6 317 100 cubic metres in any one day, or 800 000 000 cubic metres in the period;
- b) for the period commencing on the 1st day of November, 1980, and ending on the 31st day of October, 1984, 6 317 100 cubic metres in any one day, or 2 096 300 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October;
- c) for the period commencing on the 1st day of November, 1984, and ending on the 31st day of October, 1985, 4 737 800 cubic metres in any one day, or 1 572 200 000 cubic metres in the period;
- d) for the period commencing on the 1st day of November, 1985, and ending on the 14th day of December, 1985, 3 158 600 cubic metres in any one day, or 139 000 000 cubic metres in the period, or
- e) 10 896 400 000 cubic metres during the term of this licence.

3. Notwithstanding condition 2, during the period commencing with the date of commencement of the term of this licence and ending on the 14th day of May, 1981, the total quantity of gas that may be exported in any one day under the authority of and in accordance with this licence shall not exceed the difference between 6 317 100 cubic metres and the quantity of gas exported under Licence No. GL-1 on that day.
4. Notwithstanding conditions 2 and 3 and for the purpose only of alleviating temporary operating problems caused by pipeline or equipment failure, the quantity of gas that may be exported in any one day shall not exceed 110 percent of the quantity that may be otherwise exported in any one day.
5. As a tolerance, the amount the Licensee may export under this licence may, in any 24-hour period, exceed the daily limitation imposed in condition 2 by two percent of such amount.
6. (1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.

(2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.
7. Gas exported under the authority of and in accordance with this licence shall be exported at a place on the international boundary line between Canada and the United States of America near Emerson in the Province of Manitoba.

8. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
9. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

To Consolidated Natural Gas Limited

A. A licence for the exportation of gas at a point near Emerson, Manitoba with the following terms and conditions:

1. The term of this licence shall commence on the 1st day of November, 1980, and end on the 31st day of October, 1987.
2. The quantity of gas that may be exported under the authority of and in accordance with this licence shall not exceed:
 - (a) for the period commencing on the 1st day of November, 1980, and ending on the 31st day of October, 1984, 5 665 600 cubic metres in any one day, or 2 067 900 000 cubic metres in any consecutive twelve-month period ending on the 31st day of October;
 - (b) for the period commencing on the 1st day of November, 1984 and ending on the 31st day of October, 1985, 4 249 200 cubic metres in any one day, or 1 551 000 000 cubic metres in the period;
 - (c) for the period commencing on the 1st day of November, 1985, and ending on the 31st day of October, 1986, 2 832 800 cubic metres in any one day, or 1 034 000 000 cubic metres in the period;
 - (d) for the period commencing on the 1st day of November, 1986, and ending on the 31st day of October, 1987, 1 416 400 cubic metres in any one day, or 517 000 000 cubic metres in the period, or
 - (e) 11 373 600 000 cubic metres during the term of this licence.

3. As a tolerance, the amount the Licensee may export under this licence may, in any 24-hour period, exceed the daily limitation imposed in condition 2 by two percent of such amount.
- 4.(1) The price to be received for gas exported in each month comprised in the term of this licence, including all transmission costs of moving gas to the international boundary line between Canada and the United States of America, shall be not greater than and not less than the Canadian dollar equivalent for each such month of \$3.22 in United States currency per gigajoule of gross heating value.
- (2) The Canadian dollar equivalent for each month comprised in the term of this licence shall be an amount in Canadian dollars equal to the price in United States dollars specified in subcondition (1), converted to Canadian dollars at the rate of exchange for each such month, which rate of exchange shall be the average of the noon spot exchange rates for the United States dollar in terms of Canadian dollars in each such month, as published by the Bank of Canada.
5. Gas exported under the authority of and in accordance with this licence shall be exported at a place on the international boundary line between Canada and the United States of America near Emerson in the Province of Manitoba.
6. The quantity, relative density and gross heating value of all gas exported under the authority of and in accordance with this licence shall be measured by the Licensee in a manner approved by the Board.
7. The Licensee shall, within 15 days of the end of each month comprised in the term of this licence, file with the Board a report setting forth the daily quantities, relative density and gross heating value of the gas exported hereunder.

